4–4–07 Wednesday
Vol. 72 No. 64 Apr. 4, 2007

Pages 16261-16694

Federal Register

The **FEDERAL REGISTER** (ISSN 0097–6326) is published daily, Monday through Friday, except official holidays, by the Office of the Federal Register, National Archives and Records Administration, Washington, DC 20408, under the Federal Register Act (44 U.S.C. Ch. 15) and the regulations of the Administrative Committee of the Federal Register (1 CFR Ch. I). The Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402 is the exclusive distributor of the official edition. Periodicals postage is paid at Washington, DC.

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The Code of Federal Regulations is sold by the Superintendent of Documents. Prices of new books are listed in the first FEDERAL REGISTER issue of each week.

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

7 CFR Part 915

[Docket No. AMS–FV–06–0170; FV07–915–1 FIR]

Avocados Grown in South Florida; Suspension of Weekly Handler Reporting Requirements

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Final rule.

SUMMARY: The Department of Agriculture (USDA) is adopting, as a final rule, without change, an interim final rule changing the reporting requirements currently prescribed under the marketing order for avocados grown in South Florida (order). The order regulates the handling of avocados grown in South Florida and is administered locally by the Avocado Administrative Committee (Committee). This rule continues in effect the action that indefinitely suspended the weekly handler reporting requirements specified under the order. The information from the weekly reports is no longer being used by the industry or the Committee staff and the germane information is available from other sources. This action reduces the reporting burden on handlers, while aligning information collection requirements with the needs of the industry.

DATES: *Effective Date:* May 4, 2007.

FOR FURTHER INFORMATION CONTACT: William G. Pimental, Marketing Specialist, or Christian D. Nissen, Regional Manager, Southeast Marketing Field Office, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA; Telephone: (863) 324–3375, Fax: (863) 325–8793 or E-mail: *William.Pimental@usda.gov* or *Christian.Nissen@usda.gov*, respectively.

Small businesses may request information on complying with this regulation by contacting Jay Guerber, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1400 Independence Avenue, SW., STOP 0237, Washington, DC 20250–0237; Telephone: (202) 720–2491, Fax: (202) 720–8938, or E-mail: *Jay.Guerber@usda.gov.*

SUPPLEMENTARY INFORMATION: This rule is issued under Marketing Agreement No. 121 and Marketing Order No. 915, both as amended (7 CFR part 915), regulating the handling of avocados grown in South Florida, hereinafter referred to as the ''order.'' The order is effective under the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601–674), hereinafter referred to as the ''Act.''

USDA is issuing this rule in conformance with Executive Order 12866.

This rule has been reviewed under Executive Order 12988, Civil Justice Reform. This rule is not intended to have retroactive effect. This rule will not preempt any State or local laws, regulations, or policies, unless they present an irreconcilable conflict with this rule.

The Act provides that administrative proceedings must be exhausted before parties may file suit in court. Under section 608c(15)(A) of the Act, any handler subject to an order may file with USDA a petition stating that the order, any provision of the order, or any obligation imposed in connection with the order is not in accordance with law and request a modification of the order or to be exempted therefrom. A handler is afforded the opportunity for a hearing on the petition. After the hearing USDA would rule on the petition. The Act provides that the district court of the United States in any district in which the handler is an inhabitant, or has his or her principal place of business, has jurisdiction to review USDA's ruling on the petition, provided an action is filed not later than 20 days after the date of the entry of the ruling.

This rule continues in effect the action that modified the reporting requirements prescribed under the order by indefinitely suspending the weekly handler reporting requirements. The information from the weekly report is no longer being used by the industry or the Committee staff and the germane information is available from other sources. This action reduces the reporting burden on handlers, while aligning information collection requirements with the needs of the industry. The Committee unanimously recommended this change at a meeting on April 19, 2006.

Section 915.60 of the avocado marketing order provides authority for the Committee to require handlers to file reports and provide other information as may be necessary for the Committee to perform its duties. Section 915.150 of the order's rules and regulations specifies the requisite reporting requirements.

This rule continues in effect the action that revised § 915.150 by indefinitely suspending paragraphs (a), (b), and (c) which specify the weekly handler reporting requirements. Prior to this action, handlers were required to submit a weekly report to the Committee listing all avocados handled, the disposition of each lot of noncertified avocados removed from handler's premises, and each lot of noncertified avocados received from another district. The Committee provided a form to assist handlers with supplying the required information. This information was compiled into a report which was made available to the industry. The Committee also used this data for statistical reporting purposes, to assess handlers, and for program compliance.

When instituted, the information from the weekly reports was adequate for industry and Committee needs. However, for the past several seasons, the industry has stopped requesting the reports compiled from the weekly data. The Committee believes timely data is necessary for the information to be valuable. The industry is still interested in the volume of avocados handled, but weekly reports are not timely enough to be beneficial when it comes to using such information to help growers and handlers make harvesting and packing decisions.

In addition to the weekly reporting information, the Committee staff also receives daily shipment information for all avocado handlers from the Federal-State Inspection Service (FSIS). This information is collected from handlers

at the time of inspection and includes information on the volume packed. The Committee staff uses this information to generate daily shipping reports. The reports generated from the FSIS information are more accurate and timely, and the industry finds this information to be more beneficial. As such, the Committee staff has stopped generating reports based on the weekly information.

Further, the Committee has found reporting at the time of inspection to be an effective and efficient way of collecting information. Recently, the rules and regulations were amended to require handlers to report added information to the FSIS at the time of inspection (70 FR 59622, October 13, 2005). With that change, handlers are now required to provide information regarding the number of avocados pack per container, in addition to the previous requirement that handlers provide the number and sizes of containers packed.

In comparison, handlers find weekly reporting to be time consuming and that it places an additional burden on their staff to ensure weekly reports are submitted. Also, with some of the information contained in the weekly report already being reported at the time of inspection, it represents a duplication of effort.

At one time, the Committee staff used the information from the weekly handler reports for statistical reporting purposes, to assess handlers, and for program compliance. However, they too have found the information in the daily shipment reports to be more useful, and of more interest to the industry. Further, the Committee staff has not been using the weekly reports to support program operations or for compliance purposes for some time. The information needed for Committee operations, marketing policies, and compliance is available from the daily inspection information provided by FSIS and from other sources.

In addition, damages sustained from hurricanes in 2004 and 2005 resulted in a substantial reduction in assessment income. This rule reduces the amount of time required by the Committee staff to monitor handler reports. Thus, this rule offers the potential for cost savings.

This rule continues in effect the action that indefinitely suspended the provisions requiring the submission of the weekly handler report. The information collected under this requirement is no longer being utilized and is not necessary for the operations of the order. This action reduces the reporting burden on handlers and lessens the reporting oversight demands on the Committee staff. Therefore, the Committee voted unanimously to suspend § 915.150 paragraphs (a), (b), and (c).

Section 8e of the Act provides that when certain domestically produced commodities, including avocados, are regulated under a Federal marketing order, imports of that commodity must meet the same or comparable grade, size, quality, and maturity requirements. As this rule changes the reporting requirements under the domestic handling regulations, no corresponding changes to the import regulations are required.

Final Regulatory Flexibility Analysis

Pursuant to requirements set forth in the Regulatory Flexibility Act (RFA), the Agricultural Marketing Service (AMS) has considered the economic impact of this action on small entities. Accordingly, AMS has prepared this final regulatory flexibility analysis.

The purpose of the RFA is to fit regulatory actions to the scale of business subject to such actions in order that small businesses will not be unduly or disproportionately burdened. Marketing orders issued pursuant to the Act, and the rules issued thereunder, are unique in that they are brought about through group action of essentially small entities acting on their own behalf. Thus, both statutes have small entity orientation and compatibility.

There are approximately 300 producers of avocados in the production area and approximately 35 handlers subject to regulation under the order. Small agricultural producers are defined by the Small Business Administration (SBA) as those having annual receipts of less than $750,000, and small agricultural service firms are defined as those whose annual receipts are less than $6,500,000 (13 CFR 121.201).

According to the National Agricultural Statistics Service and Committee data, the average price for Florida avocados during the 2005–06 season was around $46.75 per 55-pound bushel container, and total shipments were near 470,000 55-pound bushel equivalents. Using the average price and shipment information provided by the Committee, the majority of avocado handlers could be considered small businesses under the SBA definition. In addition, based on avocado production, grower prices, and the total number of Florida avocado growers, the average annual grower revenue is less than $750,000. Thus, the majority of Florida avocado producers may also be classified as small entities.

This rule changes the reporting requirements currently prescribed under the order. This rule continues in effect the action that indefinitely suspended the weekly handler reporting requirements required under the order. The information from the weekly report is no longer being used by the industry or the Committee staff and the germane information is available from other sources. This action reduces the reporting burden on handlers, while aligning information collection requirements with the needs of the industry. This rule revises § 915.150, which specifies the requisite reporting requirements. Authority for this action is provided for in § 915.60 of the order. The Committee unanimously recommended this change at a meeting held on April 19, 2006.

This rule is not expected to result in any additional costs for handlers. This rule continues in effect the action that reduced the reporting burden on handlers by indefinitely suspending the provisions requiring the submission of a weekly report. It also reduces the amount of time required by the Committee staff to monitor and review handler reports. Thus, this rule offers the potential for cost savings. The potential reduction in costs would benefit all handlers regardless of their size. Consequently, the benefits of this rule are expected to be equally available to all.

The Committee discussed keeping the weekly reporting requirements in place as an alternative to this action. However, the Committee believes continuing to collect information that is no longer being utilized by the industry or the Committee staff is unnecessary. Therefore, this alternative was rejected.

This rule will not impose any additional reporting or recordkeeping requirements on either small or large avocado handlers. The form, FV–215, ''Avocado Handler's Weekly Report Form'' is currently approved under OMB No. 0581–0189, Generic OMB Fruit Crops. The information collection for OMB No. 1581–0189 will be coming up for renewal, at which time the reduction in burden for this form will be addressed. The suspension of the reporting requirement reduces the overall burden for that collection by 54 hours. As with all Federal marketing order programs, reports and forms are periodically reviewed to reduce information requirements and duplication by industry and public sector agencies. In addition, USDA has not identified any relevant Federal rules that duplicate, overlap or conflict with this rule.

The AMS is committed to complying 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.

Further, the Committee's meeting was widely publicized throughout the avocado industry and all interested persons were invited to attend the meeting and participate in Committee deliberations. Like all Committee meetings, the April 19, 2006, meeting was a public meeting and all entities, both large and small, were able to express their views on this issue.

An interim final rule concerning this action was published in the **Federal Register** on December 22, 2006. Copies of the rule were mailed by the Committee's staff to all Committee members and avocado handlers. In addition, the rule was made available through the Internet by USDA and the Office of the Federal Register. That rule provided for a 60-day comment period which ended February 20, 2007. No comments were received.

A small business guide on complying with fruit, vegetable, and specialty crop marketing agreements and orders may be viewed at: *http://www.ams.usda.gov/fv/moab.html.* Any questions about the compliance guide should be sent to Jay Guerber at the previously mentioned address in the **FOR FURTHER INFORMATION CONTACT** section.

After consideration of all relevant material presented, including the Committee's recommendation, and other information, it is found that finalizing the interim final rule, without change, as published in the **Federal Register** (71 FR 76897, December 22, 2006) will tend to effectuate the declared policy of the Act.

List of Subjects in 7 CFR Part 915

Avocados, Marketing agreements, Reporting and recordkeeping requirements.

PART 915—AVOCADOS GROWN IN SOUTH FLORIDA

■ Accordingly, the interim final rule amending 7 CFR part 915 which was published at 71 FR 76897 on December 22, 2006, is adopted as a final rule without change.

Dated: March 29, 2007.

Lloyd C. Day,

Administrator, Agricultural Marketing Service.

[FR Doc. E7–6243 Filed 4–3–07; 8:45 am]

BILLING CODE 3410–02–P

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

7 CFR Part 922

[Docket No. AMS–FV–07–0031; FV07–922–1 IFR]

Apricots Grown in Designated Counties in Washington; Suspension of Container Regulations

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Interim final rule with request for comments.

SUMMARY: This rule suspends the container regulations prescribed under the Washington apricot marketing order by extending the temporary 2006 season suspension indefinitely. The marketing order regulates the handling of fresh apricots grown in designated counties in the State of Washington, and is administered locally by the Washington Apricot Marketing Committee (Committee). This indefinite suspension of the container regulations will continue to provide the apricot industry with increased marketing flexibility by allowing handlers to pack and ship apricots in any size, shape, or type of container. After evaluating the impact the temporary 2006 season container regulation suspension has had on the industry, the Committee determined that container regulations no longer contribute to the orderly marketing of the fresh apricot crop.

DATES: Effective April 1, 2007. Comments received by June 4, 2007 will be considered prior to issuance of a final rule.

ADDRESSES: Interested persons are invited to submit written comments concerning this rule. Comments must be sent to the Docket Clerk, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1400 Independence Avenue, SW., STOP 0237, Washington, DC 20250–0237; *Fax:* (202) 720–8938; or *Internet: http://www.regulations.gov.* All comments should reference the docket number and the date and page number of this issue of the **Federal Register** and will be made available for public inspection in the Office of the Docket Clerk during regular business hours or can be viewed at: *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Robert J. Curry or Gary D. Olson, Northwest Marketing Field Office, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1220 SW., Third Avenue, Suite 385, Portland, Oregon 97204–2807; *Telephone:* (503) 326–2724; *Fax:* (503) 326–7440; or *E-mail: Robert.Curry@usda.gov* or *GaryD.Olson@usda.gov.*

Small businesses may request information on complying with this regulation by contacting Jay Guerber, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1400 Independence Avenue, SW., STOP 0237, Washington, DC 20250–0237; *Telephone:* (202) 720–2491; Fax: (202) 720–8938; or *E-mail: Jay.Guerber@usda.gov.*

SUPPLEMENTARY INFORMATION: This rule is issued under Marketing Agreement and Order No. 922 (7 CFR part 922) regulating the handling of apricots grown in designated counties in Washington, hereinafter referred to as the ''order.'' The order is effective under the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601–674), hereinafter referred to as the ''Act.''

The Department of Agriculture (USDA) is issuing this rule in conformance with Executive Order 12866.

This rule has been reviewed under Executive Order 12988, Civil Justice Reform. This rule is not intended to have retroactive effect. This rule will not preempt any State of local laws, regulations, or policies, unless they present an irreconcilable conflict with this rule.

The Act provides that administrative proceedings must be exhausted before parties may file suit in court. Under section 608c(15)(A) of the Act, any handler subject to an order may file with USDA a petition stating that the order, any provision of the order, or any obligation imposed in connection with the order is not in accordance with law and request a modification of the order or to be exempted therefrom. Such handler is afforded the opportunity for a hearing on the petition. After the hearing USDA would rule on the petition. The Act provides that the district court of the United States in any district in which the handler is an inhabitant, or has his or her principal place of business, has jurisdiction to review USDA's ruling on the petition, provided an action is filed not later than 20 days after the date of the entry of the ruling.

This rule indefinitely extends the temporary 2006 season container regulation suspension (§ 922.306), which ends on March 31, 2007. As it effectively did during the 2006 shipping season, this regulatory suspension will provide additional flexibility to the apricot industry by allowing handlers to

pack apricots in any type, shape, or size container. The container regulations prescribed under § 922.306 will remain suspended for the 2007 and future seasons unless the Committee recommends, and USDA approves, action to reinstate the regulations. For the 2006 season, the Committee recommended a temporary suspension of the regulations rather than an open-ended suspension to help ensure that a thorough analysis of the 2006 shipping season would be completed prior to any potential future action regarding the issue of container regulation suspension. The Committee has reviewed the 2006 shipping season and determined that the industry can successfully market its fresh apricot crop without the container regulations in place. Consequently, the Committee has concluded that the Washington apricot industry is now best served by an open-ended suspension of § 922.306. To facilitate prompt reinstatement of the container regulations in the future should market conditions warrant such, the Committee recommended that the 2006 temporary regulation suspension be extended rather than replaced by a permanent removal of the regulations from the order.

Section 922.52 of the order authorizes the issuance of regulations for grade, size, quality, maturity, pack, and container for any variety of apricots grown in the production area. Section 922.52(a)(3) specifically authorizes the establishment of the container regulations found in § 922.306. Section 922.53 authorizes the modification, suspension, or termination of regulations issued pursuant to § 922.52.

Authority to regulate the size, weight, dimension and pack of containers used in the marketing of fresh apricots was included in the order when promulgated in 1957. Container regulatory authority was included in the order to provide container standardization, to enhance orderly marketing conditions, and to provide for increased producer returns.

The Committee meets prior to each season to consider recommendations for modification, suspension, or termination of any regulatory requirements for Washington apricots that are issued on a continuing basis. Committee meetings are open to the public and interested persons may express their views at these meetings. The USDA reviews the Committee recommendations along with any supportive information submitted by the Committee, as well as information from other available resources, and determines whether modification, suspension, or termination of the regulatory requirements would tend to effectuate the declared policy of the Act.

During such a review at its February 15, 2007, meeting, the Committee determined, and unanimously recommended, that the 2006 season container regulation suspension—effective from April 1, 2006, through March 31, 2007—be extended indefinitely. For a seamless extension of the suspension, the Committee recommended that this rule be effective by April 1, 2007.

When effective, § 922.306 provides that apricots must be handled domestically in (1) open containers or telescopic fiberboard cartons weighing 28 pounds or greater; (2) closed containers with 14 pounds or more of apricots packed in a row-faced or tray-pack configuration; (3) closed containers with 12 pounds (or more) of random sized, non row-faced apricots; or (4) closed containers with 24 pounds or more of loose-packed apricots.

In reaching a consensus to extend the 2006 regulatory suspension, Committee members found that arguments made in favor of the suspension at the meeting a year ago are still appropriate. They noted that container standardization had contributed to orderly marketing in the past, but buyers today are increasingly interested in non-traditional packaging options designed for better handling and greater consumer acceptance. Furthermore, handler members stated that they now enjoy a greater latitude in choosing the optimum container weight for a particular pack or customer. Committee members were unanimous in the opinion that this indefinite extension of the container regulation suspension will continue to provide the industry with the flexibility needed to meet the challenges of marketing fresh apricots.

Initial Regulatory Flexibility Analysis

Pursuant to requirements set forth in the Regulatory Flexibility Act (RFA), the Agricultural Marketing Service (AMS) has considered the economic impact of this rule on small entities. Accordingly, AMS has prepared this initial regulatory flexibility analysis.

The purpose of the RFA is to fit regulatory actions to the scale of business subject to such actions in order that small businesses will not be unduly or disproportionately burdened. Marketing orders issued pursuant to the Act, and the rules issued thereunder, are unique in that they are brought about through group action of essentially small entities acting on their own behalf. Thus, both statutes have small entity orientation and compatibility.

There are approximately 300 apricot producers within the regulated production area and approximately 22 regulated handlers. Small agricultural producers are defined by the Small Business Administration (SBA)(13 CFR 121.201) as those having annual receipts of less than $750,000, and small agricultural service firms are defined as those whose annual receipts are less than $6,500,000.

Data from the Washington Agricultural Statistics Service shows that the total 5,900 ton Washington apricot utilization sold for an average of $969 per ton in 2005 with a total value of $5,715,000. Based on the number of producers in the production area (300), the average annual producer revenue from the sale of apricots in 2005 can thus be estimated at approximately $19,050. In addition, based on information from the Committee and USDA's Market News Service, 2005 f.o.b. prices ranged from $15.00 to $20.00 per 24-pound loose-pack container, and from $14.00 to $24.00 for 2-layer tray pack containers. Assuming that equal quantities of the 2005 season fresh apricot pack-out of 4,471 tons went into loose-pack (24-pound) containers and tray-pack containers (weighing an average of about 20 pounds each), average gross receipts per handler from the sale of fresh apricots would have been approximately one half of the annual sales figure that the SBA uses to define the minimum size of a large agricultural service business ($750,000). Thus, the majority of producers and handlers of Washington apricots may be classified as small entities.

At its February 15, 2007, meeting the Committee recommended that the temporary suspension of the order's container regulations (§ 922.306)—effective from April 1, 2006, through March 31, 2007—be indefinitely extended to cover the 2007 shipping season as well as all future seasons. Section 922.52(a)(3) of the order specifically authorizes the establishment of container regulations. Further, § 922.53 authorizes the modification, suspension, or termination of regulations issued pursuant to § 922.52. This indefinite extension of the container regulation suspension is expected to continue to provide the apricot industry with increased marketing flexibility by allowing handlers to pack and ship apricots in any size, shape, or type of container. Container regulations have been utilized in past seasons to provide a degree of standardization and thus have helped in providing the industry with orderly marketing conditions.

However, changing market dynamics and the experience gained through the 2006 suspension have convinced the Committee that container standardization is no longer necessary to ensure orderly marketing. Last year, rather than seeking an indefinite suspension of the regulations, the Committee recommended a temporary suspension so that it could conduct a thorough evaluation of the impact the relaxation would have on the industry during the 2006 shipping season prior to taking any further action for subsequent seasons. In reviewing the 2006 season at the February 15, 2007, meeting, the Committee easily reached a consensus that an indefinite continuation of the container regulation suspension would best fit the industry's marketing needs.

The Committee anticipates that this rule will not negatively impact small businesses. This rule extends the suspension of the container requirements found under § 922.306 of the order's rules and regulations and should continue to provide enhanced marketing opportunities.

The Committee discussed—and subsequently rejected—alternatives to its recommendation to extend the container regulation suspension. These included allowing the reinstatement of the regulations (by not taking any action) and continuing with annual and temporary regulatory suspensions such as recommended for the 2006 season. With a successful season behind them, Committee members were unanimous in their decision to recommend to USDA an extension of the container regulations suspension for an indefinite period.

This rule will not impose any additional reporting or recordkeeping requirements on either small or large apricot handlers. As with all Federal marketing order programs, reports and forms are periodically reviewed to reduce information requirements and duplication by industry and public sector agencies. In addition, USDA has not identified any relevant Federal rules that duplicate, overlap or conflict with this rule.

AMS is committed to complying 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.

The Committee's meeting was widely publicized throughout the Washington apricot industry and all interested persons were invited to attend the meeting and participate in Committee deliberations. Like all Committee meetings, the February 15, 2007, meeting was a public meeting and all entities, both large and small, were able to express their views on this issue.

A small business guide on complying with fruit, vegetable, and specialty crop marketing agreements and orders may be viewed at: *http://www.am.usda.gov/fv/moab.html.* Any questions about the compliance guide should be sent to Jay Guerber at the previously mentioned address in the **FOR FURTHER INFORMATION CONTACT** section.

This rule invites comments on an indefinite extension of the suspension of the container regulations under the Washington apricot marketing order. Any comments received will be considered prior to finalization of this rule.

After consideration of all relevant material presented, including the Committee's recommendation, and other information, it is found that the suspension of the order's container regulations should be indefinitely extended in order to effectuate the declared policy of the Act.

Pursuant to 5 U.S.C. 553, it is also found and determined upon good cause that it is impracticable, unnecessary, and contrary to the public interest to give preliminary notice prior to putting this rule into effect and that good cause exists for not postponing the effective date of this rule until 30 days after publication in the **Federal Register** because: (1) This rule extends the 2006 season container regulation suspension for Washington apricots to include the 2007 and future shipping seasons; (2) the indefinite extension of the container regulation suspension was unanimously recommended by the Committee at a public meeting and all interested persons had an opportunity to express their views and provide input; (3) Washington apricot handlers are aware of this recommendation, are currently operating under relaxed regulatory conditions, and need no additional time to comply with the continued relaxed requirements; (4) this rule should be in effect by April 1, 2007, to ensure a seamless continuation of the current container regulation suspension; and (5) this rule provides a 60-day comment period, and any comments received will be considered prior to finalization of this rule.

List of Subjects in 7 CFR Part 922

Apricots, Marketing agreements, Reporting and recordkeeping requirements.

■ For the reasons set forth in the preamble, 7 CFR part 922 is amended as follows:

PART 922—APRICOTS GROWN IN DESIGNATED COUNTIES IN WASHINGTON

■ 1. The authority citation for 7 CFR part 922 continues to read as follows:

Authority: 7 U.S.C. 601–674.

§ 922.306 [Suspended]

■ 2. In part 922, § 922.306 is suspended indefinitely.

Dated: March 29, 2007.

Lloyd C. Day,

Administrator, Agricultural Marketing Service.

[FR Doc. E7–6224 Filed 4–3–07; 8:45 am]

BILLING CODE 3410–02–P

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

7 CFR Part 926

[Docket No. AMS–FV–06–0173; FV06–926–1 FIR]

Data Collection, Reporting and Recordkeeping Requirements Applicable to Cranberries Not Subject to the Cranberry Marketing Order; Suspension of Provisions Under 7 CFR Part 926

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Final rule.

SUMMARY: The U.S. Department of Agriculture (USDA) is adopting, as a final rule, without change, an interim final rule suspending Part 926 in the Code of Federal Regulations, which requires persons engaged in the handling or importation of fresh cranberries or cranberry products, but not subject to the reporting requirements of the Federal cranberry marketing order (7 CFR part 929), to report sales, acquisition, and inventory information to the Cranberry Marketing Committee (Committee), and to maintain adequate records of such activities. The establishment of these requirements is authorized under section 8(d) of the Agricultural Marketing Agreement Act of 1937 (Act). The Committee, which administers marketing order 929, regulating the handling of cranberries grown in Massachusetts, Rhode Island, Connecticut, New Jersey, Wisconsin, Michigan, Minnesota, Oregon, Washington, and Long Island in the State of New York, has been delegated by USDA to collect such information authorized under Part 926. Based on information provided by the Committee, USDA has determined that the

collection of information under Part 926 is of marginal benefit to the industry and should continue to be suspended.

DATES: *Effective Date:* May 4, 2007.

FOR FURTHER INFORMATION CONTACT: Patricia A. Petrella or Kenneth G. Johnson, DC Marketing Field Office, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, Unit 155, 4700 River Road, Riverdale, Maryland 20737; Telephone: (301) 734–5243, Fax: (301) 734–5275, or E-mail at *Patricia.Petrella@usda.gov* or *Kenneth.Johnson@usda.gov.*

Small businesses may request information on complying with this regulation by contacting Jay Guerber, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1400 Independence Avenue, SW., STOP 0237, Washington, DC 20250–0237; Telephone: (202) 720–2491, Fax: (202) 720–8938, or E-mail: *Jay.Guerber@usda.gov.*

SUPPLEMENTARY INFORMATION: This rule is issued pursuant to the Agricultural Marketing Agreement Act of 1937, as amended [7 U.S.C. 601–674], hereinafter referred to as the ''Act''.

USDA is issuing this rule in conformance with Executive Order 12866.

This rule has been reviewed under Executive Order 12988, Civil Justice Reform. This rule is not intended to have retroactive effect. This rule will not preempt any State or local laws, regulations, or policies, unless they present an irreconcilable conflict with this rule. There are no administrative procedures which must be exhausted prior to any judicial challenge to the provisions of this rule.

This rule continues in effect the action that suspended indefinitely Part 926 of the Code of Federal Regulations, which contains the reporting and recordkeeping requirements for entities engaged in the handling or importation of fresh cranberries or cranberry products but not subject to the cranberry marketing order (7 CFR part 929) (order). Under Part 926, such entities are required to provide to USDA or its delegate, certain information regarding the sales, acquisitions, and inventories of fresh cranberries or cranberry products. USDA delegated authority to the Committee to collect such information. The Committee, which is also responsible for administering the order, has used this information to analyze market conditions and make volume control recommendations to USDA. The Committee has determined that this data collection under Part 926 is not needed at this time, and advised USDA of its findings following its meeting on June 6, 2006.

Section 608d(3) of the Act, as amended, authorizes the collection of cranberry and cranberry product inventory information from producer-handlers, second handlers, processors, brokers, and importers that are not regulated by the order. Pursuant to this statutory authority, USDA issued reporting and recordkeeping requirements for these entities under Part 926 on January 12, 2005 (70 FR 1995). Sections 926.16, 926.17, and 926.18 require these entities to file and maintain certain reports and other information that are also required of handlers regulated under the order.

Part 926 was implemented to allow the Committee access to cranberry and cranberry product inventory information from throughout the industry, including segments outside the scope of the order, so that it could make more informed marketing decisions. For example, the Committee makes annual volume control recommendations to USDA that are based upon estimated cranberry production, acquisition, inventory, and sales for the total industry. Adding inventory data collected from entities outside the order to the data reported by handlers under the order was expected to provide a more accurate estimate of the total industry inventory, thus enabling the Committee to make more informed volume control recommendations.

However, after more than a year's experience collecting the data pursuant to Part 926, the Committee has found that most inventories are maintained by handlers regulated under the order, and that the amount of cranberries and cranberry products held by entities outside the order is minimal and does not affect the Committee's marketing decisions. The Committee met on June 6, 2006, to evaluate the effectiveness of the data collection conducted under Part 926. Taking into account the marginal benefits of this data collection, the committee advised USDA that the reporting and recordkeeping provisions under Part 926 should be suspended.

This action continues in effect, an interim final rule suspending the reporting and recordkeeping requirements of Part 926 indefinitely. Should changes occur in the cranberry industry that would warrant reimplementation of these requirements USDA may take appropriate action to reinstate these provisions under Part 926.

Final Regulatory Flexibility Analysis

Pursuant to requirements set forth in the Regulatory Flexibility Act (RFA), the Agricultural Marketing Service (AMS) has considered the economic impact of this action on small entities. Accordingly, AMS has prepared this final regulatory flexibility analysis.

The purpose of the RFA is to fit regulatory actions to the scale of business subject to such actions in order that small businesses will not be unduly or disproportionately burdened. Small agricultural service firms are defined by the Small Business Administration (SBA) [13 CFR 121.201] as those having annual receipts less than $6,500,000. Small agricultural producers are defined as those with annual receipts of less than $750,000. The Committee estimates that there are approximately 56 handlers, producer-handlers, processors, brokers, and importers subject to the data collection requirements under Part 926. The Committee further estimates that most of the entities required to file reports under Part 926 would be considered small under the SBA criteria.

This final rule continues to suspend indefinitely the provisions of 7 CFR part 926, which require persons engaged in the handling of cranberries or cranberry products (including producer-handlers, second-handlers, processors, brokers, and importers) but not subject to the order to maintain adequate records and report sales, acquisitions, and inventory information to the Committee. Part 926 was established because the Committee needed inventory information from non-regulated entities as well as those subject to the order to better formulate its marketing decisions and recommendations. It continues to be suspended because the Committee has determined that, considering the size of the inventories held outside the scope of the order, collecting that data from the non-regulated entities is of marginal benefit to the industry.

This action continues to suspend the reporting and recordkeeping requirements for these cranberry handlers and importers. It also reduces the Committee's costs associated with the collection and maintenance of that information.

Alternatives to this action included continuing to collect information as currently provided in Part 926, raising the inventory threshold that triggers the need for a non-regulated entity to report its inventory so that only those entities holding the largest inventories would be required to file reports, or requesting that non-regulated entities provide inventory information voluntarily.

However, the Committee advised USDA that most cranberries and cranberry products are currently held in the inventories of the regulated handlers until needed by processors, which greatly reduces the likelihood that large unreported inventories exist. Therefore, the collection of inventory information from entities under Part 926 no longer benefits the industry.

In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35), the information collection requirements related to this rule were previously approved by the Office of Management and Budget (OMB) and assigned OMB No. 0581–0222, Data Collection Requirements Applicable to Cranberries Not Subject to the Cranberry Marketing Order (7 CFR part 926). This information collection package expires August 31, 2007. We have submitted this information collection package (currently under OMB review) for renewal and requested OMB approval for a 1-hour burden placeholder for future reimplementation should changes occur in the cranberry industry that require reinstatement of these reporting and recordkeeping requirements under Part 926.

The AMS is committed to complying 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.

In addition, USDA has not identified any relevant Federal rules that duplicate, overlap or conflict with this rule.

An interim final rule concerning this action was published in the **Federal Register** on December 28, 2006 (7 FR 78044). Copies of the rule were made available through the Internet by the Office of the Federal Register and USDA. A 30-day comment period ending February 26, 2007, was provided to allow interested persons to respond to the interim final rule. No comments were received.

A small business guide on complying with fruit, vegetable, and specialty crop marketing agreements and orders may be viewed at: *http//www.ams.usda.gov/fv/moab/html.* Any questions about the compliance guide should be sent to Jay Guerber at the previously mentioned address in the **FOR FURTHER INFORMATION CONTACT** section.

After consideration of all relevant material presented, it is found that Part 926, as suspended in this action, as hereinafter set forth, does not tend to effectuate the declared policy of the Act and that the interim final rule, as published in the **Federal Register** (71 FR 78044, December 28, 2006), is adopted, without change, in this final rule.

List of Subjects in 7 CFR Part 926

Cranberries and cranberry products, Reporting and recordkeeping requirements.

PART 926—DATA COLLECTION, REPORTING AND RECORDKEEPING REQUIREMENTS APPLICABLE TO CRANBERRIES NOT SUBJECT TO THE CRANBERRY MARKETING ORDER

■ Accordingly, the interim final rule suspending 7 CFR part 926 which was published at 71 FR 78044 on December 28, 2006, is adopted as a final rule without change.

Dated: March 29, 2007.

Lloyd C. Day,

Administrator, Agricultural Marketing Service.

[FR Doc. E7–6241 Filed 4–3–07; 8:45 am]

BILLING CODE 3410–02–P

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

7 CFR Part 1207

[Docket No. AMS–FV–06–0177; FV–06–703–FIR]

Potato Research and Promotion Plan; Amendment of Administrative Committee Structure

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Final rule.

SUMMARY: The Department of Agriculture (USDA) is adopting, as a final rule, without change, an interim final rule amending the structure of the Administrative Committee (Committee) of the National Potato Promotion Board (Board) as prescribed in the Potato Research and Promotion Plan. This rule continues in effect the action that increased the number of Vice-Chairperson positions on the Committee from six to seven. The change is intended to more closely correlate the Committee's representation with potato production in the Northwest district—a five state region which accounts for more than half of all U.S. potato production.

DATES: *Effective Date:* May 4, 2007.

FOR FURTHER INFORMATION CONTACT: Barry Broadbent, Marketing Specialist, or Gary Olson, Regional Manager, Northwest Marketing Field Office, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1220 SW., Third Avenue, Suite 385, Portland, OR 97204; Telephone: (503) 326–2724, Fax: (503) 326–7440, or e-mail: *Barry.Broadbent@usda.gov* or *GaryD.Olson@usda.gov.*

Small businesses may request information on complying with this regulation by contacting Jay Guerber, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, 1400 Independence Avenue, SW., STOP 0237, Washington, DC 20250–0237; Telephone: (202) 720–2491, Fax: (202) 720–8938, or e-mail: *Jay.Guerber@usda.gov.*

SUPPLEMENTARY INFORMATION: This rule is issued under the Potato Research and Promotion Plan [7 CFR Part 1207], hereinafter referred to as the ''Plan.'' The Plan is authorized by the Potato Research and Promotion Act, as amended [7 U.S.C. 2611–2627], hereinafter referred to as the ''Act.''

The Office of Management and Budget (OMB) has waived the review process required by Executive Order 12866 for this action.

This rule has been reviewed under Executive Order 12988, Civil Justice Reform. This rule is not intended to have retroactive effect. This rule will not preempt any State or local laws, regulations, or policies, unless they present an irreconcilable conflict with this rule.

The Act provides that administrative proceedings must be exhausted before parties may file suit in court. Under section 311 of the Act, a person subject to a plan may file a petition with the U.S. Department of Agriculture (USDA) stating that such plan, any provision of such plan, or any obligation imposed in connection with such plan is not in accordance with law and request a modification of such plan or to be exempted therefrom. Such person is afforded the opportunity for a hearing on the petition. After the hearing, USDA would rule on the petition. The Act provides that the district court of the United States in any district in which such person is an inhabitant, or has his or her principal place of business, has jurisdiction to review USDA's ruling on the petition, provided that a complaint is filed not later than 20 days after date of the entry of the ruling.

This rule adopts the interim rule that modified the structure of the Board's Administrative Committee as prescribed in the Plan by increasing the number of Vice-Chairperson positions on the Committee from six to seven. This additional position is allocated, as provided in the Board's bylaws, to the Northwest district. This rule increased

from 25 percent to 33 percent Board representation at the executive level for potato producers in Montana, Idaho, Oregon, Washington, and Alaska is. The change was recommended by a large majority of the Board, with only 3 of 84 members dissenting at the Board's meeting on March 18, 2006.

Section 1207.327(b) of the Plan provides the authority to make rules and regulations, with USDA approval, to effectuate the terms and conditions of the Plan. Section 1207.328(a) of the Plan provides the authority to select from its members such officers as may be necessary and to adopt such rules for the conduct of its business as the Board may deem advisable.

Section 1207.507(a) of the Plan's administrative rules delineates the structure of Board's Administrative Committee. The Committee is selected from among Board members and must be composed of producer members, one or more importer member(s), and the public member. The Board, through the adoption of their bylaws, may prescribe the manner of selection and the number of members; except that the regulations mandate that the Committee shall include a Chairperson and a fixed number of Vice-Chairpersons. The bylaws also designate the officers and the immediate past Chairperson as the Board's Executive Committee.

Prior to this modification, the Plan provided for six Vice-Chairperson positions on the Committee. Vice-Chairperson positions are allocated in the Board's bylaws to represent production districts as determined by the Board. This rule adopts the interim rule that increased the number of Vice-Chairperson positions to seven. The additional Vice-Chairperson position is allocated to the Northwest district, which historically has been the district with the greatest production.

At its meeting on March 18, 2006, the Board discussed the structure of its model of governance as it relates to adequate representation of their constituents. The Board had been studying this issue for a number of years. Representatives from the potato producing districts that have experienced increases over the last 30 years expressed a desire for greater Board representation.

The Northwest district, which includes the States of Montana, Idaho, Oregon, Washington, and Alaska, has increased production such that the district now accounts for 49.5 percent of all potatoes produced by or imported into the U.S. Under the current Plan, the Northwest district accounts for 47.4 percent of the votes of the full Board, which the Board has determined to be equitable. In contrast, membership on the Executive Committee, the governing body of the Administrative Committee, is not representative of current production. The Northwest district has held only two of the eight executive positions, which represents only 25 percent of the Executive Committee vote, while production in the district has increased to nearly 50 percent.

The members agreed to a compromise solution to increase the number of officer positions on the Administrative Committee by one and, through a change in the Board's bylaws, to allocate the additional Vice-Chairperson position to the Northwest district. Eighty-one Board members voted in favor of the proposal and three members were opposed. Those in opposition represented the Northeast district and were concerned, even after the compromise proposal, that too much influence on the Board would shift to the West.

Final Regulatory Flexibility Analysis and Paperwork Reduction Act

In accordance with the Regulatory Flexibility Act (RFA)[5 U.S.C. 601 *et seq*.], the Agricultural Marketing Service has examined the impact of this rule on small entities. The purpose of the RFA is to fit regulatory actions to the scale of businesses subject to such action so that small businesses will not be disproportionately burdened.

There are approximately 1,353 handlers, 5,223 producers, and 300 importers of potatoes and potato products who are subject to the provisions of the Plan. The Small Business Administration (SBA) defines small agricultural service firms, which includes handlers and importers, as those having annual receipts of less than $6,500,000, and small agricultural producers are defined as those having annual receipts of less than $750,000. Most of the producers and handlers, and some of the importers would be classified as small businesses under the criteria established by the SBA (13 CFR 121.201). In addition, producers of less than 5 acres of potatoes are exempt from this program.

This rule adopts the interim rule that modified the structure of the Administrative Committee of the Board, as delineated under § 1207.507 of the Plan, by increasing the number of Vice-Chairperson positions from six to seven. The Plan requires that the Committee be comprised of producer Board members, one or more importer Board member(s), and the public Board member. The exact number of members seated on the Committee is determined by the Board through the Board's bylaws. Additionally, the Plan regulations require that the Board elect a Committee Chairperson and a fixed number of Vice-Chairpersons.

The Board, through their bylaws, allocates the Committee's officer positions according to production districts, so as to provide equitable representation at the executive level. The Northwest district, which has historically represented a large percentage of total potato production, has in the past been allocated two officer positions, while the other five districts have each been allocated one. Currently, producers within the Northwest district collectively produce over 50 percent of the total U.S. potato production. The additional Vice-Chairperson position created by this rule is allocated by the Board's revised bylaws to the Northwest district, thereby increasing representation for that district at the executive level from 25 percent to 33 percent. The authority for this action is provided in §§ 1207.327 and 1207.328 of the Plan.

At their March 18, 2006, meeting, the Board discussed the factors leading up to this action and the potential impact on the industry after the change. However, there is no direct financial impact to producers, handlers, or importers as a result of this action.

The Board discussed alternatives to this change, including reducing the number of districts, defining Committee representation as a ratio relative to Board members from each district, and reducing the size of the Board to the size of the existing Administrative Committee. None of the proposals garnered much support and were ultimately dropped from consideration because the changes were deemed to be too divisive to the industry.

The AMS is committed to complying 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.

This rule will not impose any additional reporting or recordkeeping requirements on either small or large potato handlers or importers. As with all Federal research and promotion programs, reports and forms are periodically reviewed to reduce information requirements and duplication by industry and public sector agencies. In addition, USDA has not identified any relevant Federal rules that duplicate, overlap, or conflict with this rule.

Further, the Board's meetings were widely publicized throughout the potato industry and all interested persons were

invited to attend the meetings and participate in Board deliberations. Like all Board meetings, the March 18, 2006, meeting was a public meeting and all entities, both large and small, were able to express their views on this issue. Finally, interested persons were invited to submit information on the regulatory and informational impacts of this action on small businesses.

An interim final rule concerning this action was published in the **Federal Register** on December 22, 2006. Copies of the rule were mailed by the Board's staff to all Board members and potato handlers. In addition, the rule was made available through the Internet by USDA and the Office of the Federal Register. The interim final rule provided for a 60-day comment period which ended February 20, 2007. Two comments were received, both of which were in support of the change.

A small business guide on complying with fruit, vegetable, and specialty crop marketing agreements and orders may be viewed at the following Web site: *http://www.ams.usda.gov/fv/moab.html.* Any questions about the compliance guide should be sent to Jay Guerber at the previously mentioned address in the **FOR FURTHER INFORMATION CONTACT** section.

After consideration of all relevant material presented, including the Board's recommendation, and other information, the interim final rule as published in the **Federal Register** (71 FR 76899, December 22, 2006), is adopted, as a final rule, without change.

List of Subjects in 7 CFR Part 1207

Advertising, Agricultural research, Imports, Potatoes, Reporting and recordkeeping requirements.

PART 1207—POTATO RESEARCH AND PROMOTION PLAN

■ Accordingly, the interim final rule amending 7 CFR part 1207 which was published at 71 FR 76899 on December 22, 2006, is adopted as a final rule without change.

Dated: March 29, 2007.

Lloyd C. Day,

Administrator, Agricultural Marketing Service.

[FR Doc. E7–6274 Filed 4–3–07; 8:45 am]

BILLING CODE 3410–02–P

COMMODITY FUTURES TRADING COMMISSION

17 CFR Parts 140 and 145

Corrections to Regional Office Information

AGENCY: Commodity Futures Trading Commission.

ACTION: Final rule.

SUMMARY: The Commodity Futures Trading Commission (''Commission'') is amending its regulations to delete references to the Minneapolis office, which was closed as of December 31, 2006, and to update the address of the Southwestern regional office.

DATES: Effective April 4, 2007.

FOR FURTHER INFORMATION CONTACT: Stacy Yochum, Deputy Executive Director, at (202) 418–5157, Office of the Executive Director, Commodity Futures Trading Commission, Three Lafayette Centre, 1155 21st St., NW., Washington DC 20581; e-mail *syochum@cftc.gov.*

SUPPLEMENTARY INFORMATION: Commission Rule 140.2 describes the organization and location of the Commission's regional offices in New York, Chicago, and Kansas City (the Eastern, Central, and Southwestern regional offices). As of December 31, 2006, the Commission closed the Minneapolis sub-office of the Southwestern regional office. In addition, the Kansas City office moved to a new location in September 2004. The Commission is therefore amending Rule 140.2 to delete the reference to the Minneapolis office and to reflect the new address of the Southwestern regional office. There is no change to the states covered by the Southwestern region. The Commission is also replacing the term ''regional director'' with ''regional coordinator'' to reflect the term used by the Commission to describe the head of each regional office.

In addition, the Commission is amending the list of addresses provided in Rule 145.6, which instructs members of the public on where to direct requests for public records, to remove the reference to the Minneapolis office and to update the Kansas City address.

List of Subjects

17 CFR Part 140

Authority delegations (Government agencies), Organization and functions (Government agencies).

17 CFR Part 145

Confidential business information, Freedom of Information.

■ Accordingly, 17 CFR parts 140 and 145 are amended as follows:

PART 140—ORGANIZATION, FUNCTIONS, AND PROCEDURES OF THE COMMISSION

■ 1. The authority citation for part 140 continues to read as follows:

Authority: 7 U.S.C. 2 and 12a.

■ 2. Section 140.2 is amended by revising the section heading, the introductory text, and paragraph (c) to read as follows:

§ 140.2 Regional Office-Regional Coordinators.

Each of the Regional offices described herein functions as set forth in this section under the direction of a Regional Coordinator who, as a collateral duty, oversees the administration of the office and represents the Commission in negotiations with employee union officials and in interactions with external parties. Each regional office has delegated authority for the enforcement of the Act and administration of the programs of the Commission in the particular regions.

* * * * *

(c) The Southwestern Regional Office is located at Two Emanuel Cleaver II Blvd., Suite 300, Kansas City, Missouri 64112, and is responsible for enforcement of the Act and administration of the programs of the Commission in the States of Alaska, Arizona, Arkansas, California, Colorado, Hawaii, Idaho, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming.

PART 145—COMMISSION RECORDS AND INFORMATION

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

Authority: Pub. L. 99–570, 100 Stat. 3207; Pub. L. 89–554, 80 Stat. 54; Pub. L. 98–502, 88 Stat. 1561–1564 (5 U.S.C. 552); Sec. 101(a), Pub. L. 93–463, 88 Stat. 1389 (5 U.S.C. 4a(j)); unless otherwise noted.

■ 4. Section 145.6 is amended by revising paragraph (a) to read as follows:

§ 145.6 Commission office to contact for assistance; registration records available.

(a) Whenever this part directs that a request be directed to the Assistant Secretary of the Commission for FOI, Privacy and Sunshine Acts Compliance, the request shall be made in writing and shall be addressed or otherwise directed to the Office of the Secretariat, Commodity Futures Trading

Commission, Three Lafayette Centre, 1155 21st Street, NW., Washington, DC 20581. Requests for public records directed to a regional office of the Commission pursuant to § 145.2 should be sent to:

Commodity Futures Trading Commission, 140 Broadway, New York, New York 10005, Telephone: (646) 746–9700.

Commodity Futures Trading Commission, 525 West Monroe Street, Suite 1100 North, Chicago, Illinois 60661, Telephone: (312) 596–0700.

Commodity Futures Trading Commission, Two Emanuel Cleaver II Blvd., Suite 300, Kansas City, Missouri 64112, Telephone: (816) 960–7700.

* * * * *

Dated: March 29, 2007.

By the Commission.

Eileen A. Donovan,

Acting Secretary of the Commission.

[FR Doc. E7–6190 Filed 4–3–07; 8:45 am]

BILLING CODE 6351–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 520

Oral Dosage Form New Animal Drugs; Praziquantel and Pyrantel

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is amending the animal drug regulations to reflect approval of an original new animal drug application (NADA) filed by Virbac AH, Inc. The NADA provides for use of chewable tablets containing praziquantel and pyrantel pamoate in dogs and puppies for the treatment and control of various internal parasites.

DATES: This rule is effective April 4, 2007.

FOR FURTHER INFORMATION CONTACT: Melanie R. Berson, Center for Veterinary Medicine (HFV–110), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855, 301–827–7540, e-mail: *melanie.berson@fda.hhs.gov*.

SUPPLEMENTARY INFORMATION: Virbac AH, Inc., 3200 Meacham Blvd., Ft. Worth, TX 76137, filed NADA 141–261 for WORMXPLUS (praziquantel and pyrantel pamoate) Flavored Chewables and VIRBANTEL (praziquantel and pyrantel pamoate) Flavored Chewables that provides for their use in dogs and puppies for the treatment and control of various internal parasites. The NADA is approved as of March 13, 2007, and 21 CFR 520.1871 is amended to reflect the approval.

In accordance with the freedom of information provisions of 21 CFR part 20 and 21 CFR 514.11(e)(2)(ii), a summary of safety and effectiveness data and information submitted to support approval of this application may be seen in the Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, rm. 1061, Rockville, MD 20852, between 9 a.m. and 4 p.m., Monday through Friday.

Under section 512(c)(2)(F)(ii) of the Federal Food, Drug, and Cosmetic Act (the act) (21 U.S.C. 360b(c)(2)(F)(ii)), this approval qualifies for 3 years of marketing exclusivity beginning March 13, 2007.

FDA has determined under 21 CFR 25.33(d)(1) that this action is of a type that does not individually or cumulatively have a significant effect on the human environment. Therefore, neither an environmental assessment nor an environmental impact statement is required.

This rule does not meet the definition of ''rule'' in 5 U.S.C. 804(3)(A) because it is a rule of ''particular applicability.'' Therefore, it is not subject to the congressional review requirements in 5 U.S.C. 801–808.

List of Subjects in 21 CFR Part 520

Animal drugs.

■ Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs and redelegated to the Center for Veterinary Medicine, 21 CFR part 520 is amended as follows:

PART 520—ORAL DOSAGE FORM NEW ANIMAL DRUGS

■ 1. The authority citation for 21 CFR part 520 continues to read as follows:

Authority: 21 U.S.C. 360b.

■ 2. Amend § 520.1871 as follows:

■ a. Revise the section heading and paragraphs (a) and (b);

■ b. Redesignate paragraph (c) as paragraph (d) and add new paragraph (c); and

■ c. Revise newly redesignated paragraphs (d)(1)(i), (d)(1)(iii), and (d)(2).

The revisions, redesignation, and addition read as follows:

§ 520.1871 Praziquantel and pyrantel.

(a) *Specifications*—(1) Each tablet contains 18.2 milligrams (mg) praziquantel and 72.6 mg pyrantel (as pyrantel pamoate).

(2) Each chewable tablet contains 30 mg praziquantel and 30 mg pyrantel pamoate or 114 mg praziquantel and 114 mg pyrantel pamoate.

(b) *Sponsors*. See sponsors in § 510.600(c) for use as in paragraph (d) of this chapter.

(1) See No. 000859 for use of tablet described in paragraph (a)(1) of this section for use as in paragraph (d)(1) of this section.

(2) See No. 051311 for use of tablets described in paragraph (a)(2) of this section for use as in paragraph (d)(2) of this section.

(c) *Special considerations*. See § 500.25 of this chapter.

(d) * * *

(1) * * *

(i) *Dosage*. 1.5 to 1.9 pounds, 1/4 tablet; 2 to 3 pounds, 1/2 tablet; 4 to 8 pounds, 1 tablet; 9 to 12 pounds, 1 1/2 tablets; 13 to 16 pounds, 2 tablets. If reinfection occurs, treatment may be repeated.

* * * * *

(iii) *Limitations*. Not for use in kittens less than 1 month of age or weighing less than 1.5 pounds. May be given directly by mouth or in a small amount of food. Do not withhold food prior to or after treatment. Consult your veterinarian before giving to sick or pregnant animals.

(2) *Dogs*—(i) *Amount*. Administer a minimum dose of 5 mg praziquantel and 5 mg pyrantel pamoate per kilogram body weight (2.27 mg praziquantel and 2.27 mg pyrantel pamoate per pound body weight) according to the dosing tables on labeling.

(ii) *Indications for use*. For the treatment and control of roundworms (*Toxocara canis* and *Toxascaris leonina*), hookworms (*Ancylostoma caninum*, *Ancylostoma braziliense*, and *Uncinaria stenocephala*), and tapeworms (*Dipylidium caninum* and *Taenia pisiformis*) in dogs and puppies.

Dated: March 26, 2007.

Stephen F. Sundlof,

Director, Center for Veterinary Medicine.

[FR Doc. E7–6181 Filed 4–3–07; 8:45 am]

BILLING CODE 4160–01–S

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 558

New Animal Drugs for Use in Animal Feeds; Melengestrol and Lasalocid

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is amending the animal drug regulations to reflect approval of an abbreviated new animal drug application (ANADA) filed by Ivy Laboratories, Div. of Ivy Animal Health, Inc. The ANADA provides for use of single-ingredient Type A medicated articles containing melengestrol and lasalocid to make two-way combination drug Type B or Type C medicated feeds for heifers fed in confinement for slaughter.

DATES: This rule is effective April 4, 2007.

FOR FURTHER INFORMATION CONTACT: John K. Harshman, Center for Veterinary Medicine (HFV–104), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855, 301–827–0169, e-mail: *john.harshman@fda.hhs.gov*.

SUPPLEMENTARY INFORMATION: Ivy Laboratories, Div. of Ivy Animal Health, Inc., 8857 Bond St., Overland Park, KS 66214, filed ANADA 200–451 for use of HEIFERMAX 500 (melengestrol acetate) Liquid Premix and BOVATEC (lasalocid sodium) single-ingredient Type A medicated articles to make dry and liquid, two-way combination drug Type B or Type C medicated feeds for heifers fed in confinement for slaughter. Ivy Laboratories' ANADA 200–451 is approved as a generic copy of NADA 140–288, sponsored by Pharmacia & Upjohn Co., a Division of Pfizer, Inc., for combination use of MGA 500 and BOVATEC. The application is approved as of March 12, 2007, and the regulations are amended in 21 CFR 558.342 to reflect the approval.

In accordance with the freedom of information provisions of 21 CFR part 20 and 21 CFR 514.11(e)(2)(ii), a summary of safety and effectiveness data and information submitted to support approval of this application may be seen in the Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, rm. 1061, Rockville, MD 20852, between 9 a.m. and 4 p.m., Monday through Friday.

The agency has determined under 21 CFR 25.33(a)(2) that this action is of a type that does not individually or cumulatively have a significant effect on the human environment. Therefore, neither an environmental assessment nor an environmental impact statement is required.

This rule does not meet the definition of ''rule'' in 5 U.S.C. 804(3)(A) because it is a rule of ''particular applicability.'' Therefore, it is not subject to the congressional review requirements in 5 U.S.C. 801–808.

List of Subjects in 21 CFR Part 558

Animal drugs, Animal feeds.

■ Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs and redelegated to the Center for Veterinary Medicine, 21 CFR part 558 is amended as follows:

PART 558—NEW ANIMAL DRUGS FOR USE IN ANIMAL FEEDS

■ 1. The authority citation for 21 CFR part 558 continues to read as follows:

Authority: 21 U.S.C. 360b, 371.

§ 558.342 [Amended]

■ 2. In § 558.342, amend the table in paragraph (e)(1)(iii) in the ''Sponsor'' column by adding in numerical sequence ''021641''.

Dated: March 26, 2007.

Stephen F. Sundlof,

Director, Center for Veterinary Medicine.

[FR Doc. E7–6180 Filed 4–3–07; 8:45 am]

BILLING CODE 4160–01–S

DEPARTMENT OF JUSTICE

Bureau of Prisons

28 CFR Parts 500 and 501

[BOP–1116; AG Order No. 2878–2007]

RIN 1120–AB08

National Security; Prevention of Acts of Violence and Terrorism

AGENCY: Bureau of Prisons, Department of Justice.

ACTION: Final rule.

SUMMARY: This rule finalizes the interim rules on Special Administrative Measures that were published on October 31, 2001 (66 FR 55062). The previously existing regulations authorized the Bureau of Prisons (Bureau), at the direction of the Attorney General, to impose special administrative measures with respect to specified inmates, based on information provided by senior intelligence or law enforcement officials, if determined necessary to prevent the dissemination of either classified information that could endanger the national security, or of other information that could lead to acts of violence and/or terrorism. The interim rule extended the period of time for which such special administrative measures may be imposed from 120 days to up to one year, and modified the standards for approving extensions of such special administrative measures. In addition, where the Attorney General has certified that reasonable suspicion exists to believe that an inmate may use communications with attorneys (or agents traditionally covered by the attorney-client privilege) to further or facilitate acts of violence and/or terrorism, the interim rule amended the previously existing regulations to provide that the Bureau must provide appropriate procedures to monitor or review such communications to deter such acts, subject to specific procedural safeguards, to the extent permitted under the Constitution and laws of the United States. The interim rule also requires the Director of the Bureau of Prisons to give written notice to the inmate and attorneys and/or agents before monitoring or reviewing any communications as described in this rule. The interim rule also provided that the head of each component of the Department of Justice that has custody of persons for whom special administrative measures are determined to be necessary may exercise the same authority to impose such measures as the Director of the Bureau of Prisons.

DATES: *Effective date:* June 4, 2007.

ADDRESSES: Rules Unit, Office of the General Counsel, Bureau of Prisons, 320 First Street, NW., Washington, DC 20534.

FOR FURTHER INFORMATION CONTACT: Sarah Qureshi, Office of the General Counsel, Bureau of Prisons, (202) 307–2105.

SUPPLEMENTARY INFORMATION: This rule finalizes interim rules on Special Administrative Measures that were published on October 31, 2001 (66 FR 55062). These rules are codified at 28 CFR 501.2 (national security) and 501.3 (violence and terrorism). We received approximately 5000 comments in opposition to the rule, which we discuss below.

Section 501.2

Section 501.2 authorizes the Director of the Bureau, at the direction of the Attorney General, to impose special administrative measures with respect to a particular inmate that are reasonably necessary to prevent disclosure of classified information. These procedures may be implemented after written certification by the head of a United States intelligence agency that the unauthorized disclosure of such information would pose a threat to the national security and that there is a danger that the inmate will disclose such information. These special administrative measures ordinarily may include housing the inmate in special housing units and/or limiting certain privileges, including, but not limited to,

correspondence, visiting, interviews with representatives of the news media, and use of the telephone, as is reasonably necessary to prevent the disclosure of classified information.

The interim rule made no change in the substantive standards for the imposition of special administrative measures, but changed the initial period of time under § 501.2 from a fixed 120-day period to a period of time designated by the Director, up to one year. The rule also allows the Director to extend the period for the special administrative measures for additional one-year periods, based on subsequent certifications from the head of an intelligence agency that there is a danger that the inmate will disclose classified information and that the unauthorized disclosure of such information would pose a threat to national security. In addition, this rule provides that the subsequent certifications by the head of an intelligence agency may be based on the information available to the intelligence agency.

Section 501.3

Section 501.3 also authorizes the Director of the Bureau, on direction of the Attorney General, to impose similar special administrative measures (with respect to a particular inmate) that are reasonably necessary to protect persons against the risk of death or serious bodily injury. These procedures may be implemented after written notification from the Attorney General or, at the Attorney General's discretion, from the head of a Federal law enforcement or intelligence agency, that there is a substantial risk that an inmate's communications or contacts with other persons could result in death or serious bodily injury to persons, or substantial damage to property that would entail the risk of death or serious bodily injury to persons.

The interim rule made no change in the substantive standards for the implementation of special administrative measures under § 501.3(a). However, the interim rule allows the Director, with the approval of the Attorney General, to impose special administrative measures for a longer period of time, not to exceed one year, in cases involving acts of violence and/or terrorism. In addition, the rule provides authority for the Director to extend the period for the special administrative measures for additional periods, up to one year, after receipt of additional notification from the Attorney General or, at the Attorney General's discretion, from the head of a Federal law enforcement or intelligence agency.

The interim rule also modified the standard for approving extensions of the special administrative measures. The rule provides that the subsequent notifications by the Attorney General, or the head of the Federal law enforcement or intelligence agency should focus on the key factual determination—that is, whether the special administrative measures continue to be reasonably necessary, at the time of each determination, because there is a substantial risk that an inmate's communications or contacts with persons could result in death or serious bodily injury to persons, or substantial damage to property that would entail the risk of death or serious bodily injury to persons.

Where the Attorney General, or the head of a Federal law enforcement or intelligence agency, initially made such a determination, then the determination made at each subsequent review should not require a de novo review, but only a determination that there is a continuing need for the imposition of special administrative measures in light of the circumstances.

In either case, the affected inmate may seek review of any special administrative measures imposed pursuant to §§ 501.2 or 501.3 in accordance with paragraph (a) of this section through the Administrative Remedy Program, 28 CFR part 542.

Justification for Special Administrative Measures Rules

Although this rule does not alter the substantive standards for the initial imposition of special administrative measures under §§ 501.2 and 501.3, the Bureau's final rule implementing this section in 1997 devoted a substantial portion of the supplementary information accompanying the rule to a discussion of the relevant legal issues. 62 FR 33730–31. As the U.S. Supreme Court noted in *Pell* v. *Procunier*, 417 U.S. 817, 822–23 (1974), ''a prison inmate retains those First Amendment rights that are not inconsistent with his status as an inmate or with the legitimate penological objectives of the corrections system. * * * An important function of the corrections system is the deterrence of crime. * * * Finally, central to all other corrections goals is the institutional consideration of internal security within the corrections facilities themselves.'' (Emphasis added.)

This regulation, with its concern for security and protection of the public, clearly meets this test. The changes made by this rule regarding the length of time and the standards for extension of periods of special administrative measures do not alter the fundamental basis of the rules that were adopted in 1997. Instead, they more clearly focus the provisions for extensions—both the duration of time and the standards—on the continuing need for restrictions on a particular inmate's ability to communicate with others within or outside the detention facility in order to avoid threats to national security or risks of terrorism and/or violence.

In every case, the decisions made with respect to a particular inmate will reflect a consideration of the issues at the highest levels of the law enforcement and intelligence communities. Where the issue is protection of national security or prevention of acts of violence and/or terrorism, it is appropriate for government officials, at the highest level and acting on the basis of their available law enforcement and intelligence information, to impose restrictions on an inmate's public contacts that may cause or facilitate such acts.

Comments

We received approximately 5000 comments in opposition to the rule. All but 44 comments were variations of two form letters. We also received one comment in support of the rule. Other than the single supporting comment, all comments expressed identical and/or overlapping themes. We discuss the comments and our responses below.

Monitoring of Attorney-Client Communications

Comment: The provision allowing monitoring of attorney-client communications breaches attorney-client privilege and deprives inmates of the right to effective assistance of counsel under the Sixth Amendment.

Response: We acknowledge that the Sixth Amendment limits the government's ability to monitor conversations between a detainee and his or her attorney. Nonetheless, as we noted in the preamble to the interim rule, the fact of monitoring by itself does not violate the Sixth Amendment right to effective assistance of counsel. *Weatherford* v. *Bursey*, 429 U.S. 545 (1977). Rather, the propriety of monitoring turns on a number of factors, including the purpose for which the government undertakes the monitoring, the protections afforded to privileged communications, and the extent to which, if at all, the monitoring results in information being communicated to prosecutors and used at trial against the detainee.

In *Weatherford*, a government informant was present at two meetings between a defendant, Bursey, and his attorney during which Bursey and the attorney discussed preparations for Bursey's criminal trial. To preserve his usefulness as an undercover agent, the informant could not reveal that he was working for the government and thus sat through the meetings and heard discussions pertaining to Bursey's defense. Bursey later brought a suit under 42 U.S.C. 1983, claiming that his Sixth Amendment right had been violated. The court of appeals found for Bursey, holding that the informant's presence during the attorney-client meetings necessarily violated Bursey's Sixth Amendment right. The Supreme Court reversed, explaining that

> [t]he exact contours of the Court of Appeals' per se right-to-counsel rule are difficult to discern; but as the Court of Appeals applied the rule in this case, it would appear that if an undercover agent meets with a criminal defendant who is awaiting trial and with his attorney and if the forthcoming trial is discussed without the agent's revealing his identity, a violation of the defendant's constitutional rights has occurred, whatever was the purpose of the agent in attending the meeting, whether or not he reported on the meeting to his superiors, and whether or not any specific prejudice to the defendant's preparation for or conduct of the trial is demonstrated or otherwise threatened. *Weatherford*, 429 U.S. at 550.

The Supreme Court expressly rejected such a *per se* rule and denied that having a government agent hear attorney-client communications results, without more, in an automatic violation of Sixth Amendment rights. Instead, the Court noted that it was significant that the government had acted not with the purpose of learning Bursey's defense strategy, but rather with the legitimate law enforcement purpose of protecting its informant's usefulness. *Id.* at 557. The Court further explained that ''unless [the informant] communicated the substance of the Bursey-Wise conversations and thereby created at least a realistic possibility of injury to Bursey or benefit to the State, there can be no Sixth Amendment violation.'' *Id.* at 557–58.

Thus, the Court indicated that the Sixth Amendment analysis requires considering the government's purpose in overhearing attorney-client consultations and whether any information from overheard consultations was communicated to the prosecution in a manner that prejudiced the defendant.

Weatherford supports the concept that when the government possesses a legitimate law enforcement interest in monitoring detainee-attorney conversations, no Sixth Amendment violation occurs so long as privileged communications are protected from disclosure and no information recovered through monitoring is used by the government in a way that deprives a defendant of a fair trial. This rule adheres to these standards by permitting monitoring only when the Attorney General certifies that reasonable suspicion exists to believe that a particular detainee may use communications with attorneys or their agents to further or facilitate acts of terrorism, and by establishing a strict firewall to ensure that attorney-client communications are not revealed to prosecutors.

Of course, if the government detects communications intended to further acts of terrorism (or other illegal acts), those communications do not fall within the scope of the attorney-client privilege. That privilege affords no protection for communications that further ongoing or contemplated illegal acts, including acts of terrorism. *See, e.g., Clark* v. *United States*, 289 U.S. 1, 15 (1933) (such a client ''will have no help from the law''). The crime-fraud exception applies even if the attorney is unaware that his professional services are being sought in furtherance of an illegal purpose, *see, e.g., United States* v. *Soudan*, 812 F.2d 920, 927 (5th Cir. 1986), and even if the attorney takes no action to assist the client, *see, e.g., In re Grand Jury Proceedings,* 87 F.3d 377, 382 (9th Cir. 1996). A detainee's efforts to use his or her lawyer to plan acts of terrorism simply are not protected by the attorney-client privilege.

This rule carefully and conscientiously balances an inmate's right to effective assistance of counsel against the government's responsibility to thwart future acts of violence and/or terrorism perpetrated with the participation or direction of Federal inmates. In those cases where the government has substantial reason to believe that an inmate may use communications with attorneys or their agents to further or facilitate acts of violence and/or terrorism, the government has a responsibility to take reasonable and lawful precautions to safeguard the public from those acts.

Comment: The monitoring provision of the rule violates the First Amendment right to petition the government, which includes the right to access courts. The commenter argued that the right to access courts involves consulting lawyers in confidence, which, according to the commenters, is infringed upon by this rule. Some commenters also argued that the provision likewise violates the Fifth Amendment by circumventing due process, which requires access to courts to ''challenge unlawful convictions and to seek redress for violations'' of constitutional rights. *Procunier* v. *Martinez*, 416 U.S. 396, 419 (1974).

Response: For the reasons set forth above in our discussion of the monitoring provision and attorney-client privilege, we disagree that the rule infringes upon inmates' rights to consult lawyers in confidence. Inmates retain the same ability to access courts and consult lawyers as they had before the date of the Special Administrative Measures interim rule. We therefore do not change the rule based on these comments.

Further, no due process rights are infringed. An inmate whose conversations with his/her attorney are monitored will enjoy strict procedural protections. First, the inmate and attorney will be notified that their communications are being monitored (§ 501.3(d)(2)). Second, a ''privilege team'' will conduct the monitoring and will be separated by a firewall from the personnel responsible for prosecuting the inmate (§ 501.3 (d)(3)). Third, the privilege team may disclose information only with the prior approval of a Federal judge or where acts of violence and/or terrorism are imminent (§ 501.3(d)(3)). The rule carefully balances inmates' need to communicate with their attorneys against the United States' need to prevent future acts of violence and/or terrorism.

Comment: The monitoring provision in the rule violates the Fourth Amendment and Federal wiretapping statutes (18 U.S.C. 2510–2522). Commenters posited that before the government can intercept oral communications, it must demonstrate to a Federal judge probable cause to believe both that a particular individual is committing a crime, and that the individual will be communicating about that crime. 18 U.S.C. 2518(3).

Response: Title 18, § 2518(7) of the United States Code allows an exception to the court order requirement upon the Attorney General's designee's determination that an emergency situation exists that involves immediate danger of death or serious physical injury to any person, or conspiratorial activities threatening the national security interest. Section 2518(7), (a)(i) and (a)(ii). Therefore, if the Attorney General so authorizes, and if, according to § 2518(7)(b), there are grounds upon which a court order could reasonably have been granted to allow interception of communications, privilege teams as authorized by the Attorney General may monitor attorney-client communications as provided for in this rule.

We note that only persons held under SAM restrictions for acts of violence or terrorism, where lives are directly at risk, may potentially be subjected to monitoring of their attorney-client conversations. Even then, such attorney-client monitoring will be resorted to only after the Attorney General has made a specific determination that it is likely that attorney-client communications will be used to convey improper messages to or from the SAM restrictee. Since the effective date of the interim rule on October 30, 2001, this provision has been invoked only once, after the government obtained specific evidence revealing that the attorney had previously misused the attorney-client privilege in order to convey improper messages to and from her client. In other words, the Attorney General determined that the situation involved ''immediate danger of death or serious physical injury to any person, or conspiratorial activities threatening the national security interest,'' under 18 U.S.C. 2518(7).

As has been recognized by the United States Supreme Court (see our response to the comment above, regarding the Sixth Amendment), the Sixth Amendment does not protect an attorney's communications with a client that are made to further the client's ongoing or contemplated criminal acts. Such communications do not assist in the preparation of a client's defense, and, therefore, are not legally privileged.

Still, before such a SAM restriction may be imposed, the Attorney General must make a specific determination that attorney-client communications will be used to circumvent the purpose of the SAM, that is, to pass information that might reasonably lead to acts of violence or terrorism resulting in death or serious bodily injury, or cause property damage that would lead to the infliction of death or serious bodily injury. Even when attorney-client communications are to be monitored for the purposes of the SAM, these communications remain subject to the attorney-client privilege to the extent recognized under applicable law.

Comment: The monitoring provision is too broad in that it applies unjustly to pretrial inmates, immigration violators, witnesses, and others in Federal (both Bureau of Prisons and non-Bureau) custody.

Response: Before this rulemaking, §§ 501.2 and 501.3 covered only inmates in Bureau of Prisons custody. However, there are instances when a person is held in the custody of other officials of the Department of Justice (for example, the Director of the United States Marshals Service). To ensure consistent application of these provisions relating to special administrative measures in those circumstances where such restrictions are necessary, this rule clarifies that the appropriate officials of the Department of Justice having custody of persons for whom special administrative measures are required may exercise the same authorities as the Director of the Bureau of Prisons and the Warden. In such cases, the persons upon whom the special administrative measures are imposed must fall within the regulatory definition of ''inmate'' at § 500.1.

Previously, the interim rule identified, as an example of an official of the Department of Justice who could exercise the same authorities as the Director of the Bureau of Prisons and the Warden, the Commissioner of the Immigration and Naturalization Service (INS). *See* 66 FR 55064 (Applicability to All Persons in Custody Under the Authority of the Attorney General). On March 1, 2003, however, the INS ceased to exist, and its functions were transferred to the Department of Homeland Security (DHS) pursuant to the Homeland Security Act of 2002 (HSA), Pub. L. No. 107–296, 116 Stat. 2135. Section 441 of the HSA transferred to DHS all functions of the detention and removal program previously under the INS Commissioner. The Secretary of Homeland Security, via Delegation No. 7030, delegated all the authority vested in section 441 of the HSA to the Immigration and Customs Enforcement (ICE), a component of DHS. Accordingly, the detention authority previously exercised by the INS Commissioner now rests with ICE. Given that ICE detainees may be housed in Bureau facilities or Bureau contract facilities, this rule would apply to those inmates.

Inmates convicted of Federal crimes, and many others in custody at Bureau facilities or Bureau contract facilities, such as pretrial inmates, witnesses, and immigration violators, have equal potential to attempt to perpetrate acts of violence and/or terrorism and/or acts that threaten national security. As discussed above and in the preamble to the interim rule (66 FR 55062), neither the special administrative measures previously authorized by this rule nor the monitoring provision currently authorized by this rule will be imposed arbitrarily. The Attorney General will carefully and systematically review each case and the potential threats before imposing special administrative measures or monitoring attorney-client communications.

Regarding ''Vagueness'' of the Rule

According to the commenters, the rule fails to

1. Detail the Administrative Remedies available if inmates oppose Special Administrative Measures (SAM). The Administrative Remedies available, which are the same for any issue an inmate wishes to pursue with the Bureau, are discussed in 28 CFR part 542.

2. Detail SAM conditions (how long confined to cell, program participation, exercise, recreation, training, association with other inmates). We do not detail SAM conditions in this rule because each case varies with the particular security needs of the inmate in question.

3. Define the ''substantial standards'' for imposing SAM.

4. Define what constitutes ''reasonable suspicion'' of terrorist activity which will prompt the Attorney General to monitor attorney-client communications.

For items 3 and 4, as we note above, we do not detail ''substantial standards'' or what will prompt monitoring of attorney-client communications because each case varies with the particular security concerns raised by each situation. In general, however, the Attorney General will determine that SAMs are necessary in light of clear evidence that communication or contact with members of the public could result in death or serious bodily injury or damage to property, as stated in the rule. Generally, this will be shown through prior acts of violence or terrorism and evidence of a continuing threat due to contacts with members of the public who may contribute to or undertake acts of violence or terrorism.

5. Define ''acts of violence or terrorism.''

The United States Code, Title 18, 2332b, describes ''[a]cts of terrorism transcending national boundaries.'' In particular, the ''Federal crime of terrorism'' is defined at length in subsection (g)(5). As such, we need not reiterate that definition in the rule text.

Regulatory Certifications

The Department has determined that this rule is a significant regulatory action for the purpose of Executive Order 12866, and accordingly this rule has been reviewed by the Office of Management and Budget.

The Department certifies, for the purpose of the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), that this rule will not have a significant economic impact on a substantial number of small entities within the meaning of the Act.

Because this rule pertains to the management of offenders committed to the custody of the Department of Justice, its economic impact is limited to the use of appropriated funds.

This rule will not have substantial direct effects on the states, the relationship between the national government and the states, or the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 13132, it is determined that this rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

List of Subjects in 28 CFR Parts 500 and 501

Prisoners.

■ Accordingly, under rulemaking authority vested in the Attorney General in 5 U.S.C. 552(a), we adopt as final the interim rule published on October 31, 2001, at 66 FR 55062, without change.

Dated: March 29, 2007.

Alberto R. Gonzales,

Attorney General.

[FR Doc. E7–6265 Filed 4–3–07; 8:45 am]

BILLING CODE 4410–05–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[CGD13–07–012]

RIN 1625–AA00

Safety Zone; Florence Rhodie Days Fireworks Display, Siuslaw River, Florence, OR

AGENCY: Coast Guard, DHS.

ACTION: Temporary final rule.

SUMMARY: The Coast Guard is establishing a temporary safety zone on the waters of the Siuslaw River during a fireworks display. The Captain of the Port, Portland, Oregon is taking this action to safeguard watercraft and their occupants from safety hazards associated with this display. Entry into this safety zone is prohibited unless authorized by the Captain of the Port.

DATES: This rule is effective on May 9, 2007 from 8:30 p.m. until 11:30 p.m. (PDT).

ADDRESSES: Documents indicated in this preamble as being available in the docket are part of docket (CGD13–07–012) and are available for inspection or copying at U.S. Coast Guard Sector Portland, 6767 N. Basin Avenue, Portland, Oregon 97217 between 7 a.m. and 4 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Petty Officer Lucia Mack, c/o Captain of the Port, Portland, 6767 N. Basin Avenue, Portland, Oregon 97217 (503–240–2590).

SUPPLEMENTARY INFORMATION:

Regulatory Information

We did not publish a notice of proposed rulemaking (NPRM) for this regulation. Under 5 U.S.C. 553(b)(B), the Coast Guard finds that good cause exists for not publishing an NPRM. If normal notice and comment procedures were followed, this rule would not become effective until after the date of the event. Publishing an NPRM would be contrary to the public interest because immediate action is necessary to ensure the safety of vessels and spectators gathering in the vicinity of the fireworks launching barge.

Background and Purpose

The Coast Guard is establishing a temporary safety zone to protect against the hazards associated with a fireworks display. This event occurs on the Siuslaw River in Florence, Oregon and is scheduled to start at 10 p.m. and end at approximately 10:15 p.m. on May 9, 2007. This event may result in a number of vessels congregating near the fireworks launching site. The safety zone is needed to protect watercraft and their occupants from safety hazards associated with fireworks displays.

Discussion of Rule

This rule establishes a safety zone to protect vessels and individuals from the hazards associated with a fireworks display. The safety zone will be located on the waters of the Siuslaw River in Florence, Oregon, encompassed by lines connecting the following points, beginning at 43°28′20″ N/124°04′46″ W, thence to 43°25′07″ N/124°04′40″ W, thence to 43°57′48″ N/124°05′54″ W, thence to 43°28′05″ N/124°05′54″ W, thence to the beginning point. This safety zone will commence prior to the launching of the fireworks in order to clear boaters out of the area for their own protection, and will last longer than the scheduled event time in case the fireworks display lasts longer than anticipated.

Entry into this zone is prohibited unless authorized by the Captain of the Port, Portland, or his designated representative. The safety zone will be enforced by representatives of the Captain of the Port, Portland, who may be assisted by other Federal, State, and local agencies.

Regulatory Evaluation

This rule is not a ''significant regulatory action'' under section 3(f) of Executive Order 12866, Regulatory Planning and Review, and does not require an assessment of potential costs and benefits under section 6(a)(3) of that Order. The Office of Management and Budget has not reviewed it under that Order. The rule is not significant because the safety zone will encompass a small portion of the river for a short duration when the vessel traffic is low.

Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we have considered whether this rule would have a significant economic impact on a substantial number of small entities. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000.

The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities. This rule will affect the following entities, some of which may be small entities: The owners or operators of vessels intending to transit or anchor in the affected portion of the Siuslaw River from 8:30 p.m. to 11:30 p.m. on May 9, 2007. This safety zone will not have a significant economic impact on a substantial number of small entities for the following reasons. This rule will be in effect for only 3 hours late in the day when vessel traffic is low. Although the safety zone will apply to the entire width of the river, traffic will be allowed to pass through the zone with the permission of the Captain of the Port, or his designated representatives on scene, if it is safe to do so. Before the effective period, the Coast Guard will issue maritime advisories widely available to users of the river.

Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we want to assist small entities in understanding the rule so that they can better evaluate its effects on them and participate in the rulemaking process. If the rule will affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please contact the person

listed in the **FOR FURTHER INFORMATION CONTACT** section.

Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247).

Collection of Information

This rule calls for no new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has a substantial direct effect on State or local governments and would either preempt State law or impose a substantial direct cost of compliance on them. We have analyzed this rule under that Order and have determined that it does not have implications for federalism.

Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or tribal government, in the aggregate, or by the private sector of $100,000,000 or more in any one year. Though this rule will not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

Taking of Private Property

This rule will not effect a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights

Civil Justice Reform

This rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden.

Protection of Children

We have analyzed this rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and does not create an environmental risk to health or risk to safety that may disproportionately affect children.

Indian Tribal Governments

This rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

Energy Effects

We have analyzed this rule under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use. We have determined that it is not a ''significant energy action'' under that order because it is not a ''significant regulatory action'' under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The Administrator of the Office of Information and Regulatory Affairs has not designated it as a significant energy action. Therefore, it does not require a Statement of Energy Effects under Executive Order 13211.

Technical Standards

The National Technology Transfer and Advancement Act (NTTAA) (15 U.S.C. 272 note) directs agencies to use voluntary consensus standards in their regulatory activities unless the agency provides Congress, through the Office of Management and Budget, with an explanation of why using these standards would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., specifications of materials, performance, design, or operation; test methods; sampling procedures; and related management systems practices) that are developed or adopted by voluntary consensus standards bodies.

This rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

Environment

We have analyzed this rule under Commandant Instruction M16475.lD, which guides the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4370f), and have concluded that there are no factors in this case that would limit the use of a categorical exclusion under section 2.B.2 of the Instruction. Therefore, this rule is categorically excluded, under figure 2–1, paragraph (34)(g), of the Instruction, from further environmental documentation because it establishes a safety zone. A final ''Environmental Check List'' and a final ''Categorical Exclusion Determination'' will be available in the docket where indicated under **ADDRESSES**.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

■ For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C. 1226, 1231; 46 U.S.C. Chapter 701; 50 U.S.C. 191, 195; 33 CFR 1.05–1(g), 6.04–1, 6.04–6 and 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. Add temporary § 165.T13–008 to read as follows:

§ 165.T13–008 Safety Zone; Florence Rhodie Days Fireworks Display, Siuslaw River, Florence, Oregon.

(a) *Location.* The following area is a safety zone: the waters of the Siuslaw River in Florence, Oregon, from surface to bottom, encompassed by the lines connecting the following points, beginning at 43°28′20″ N/124°04′46″ W, thence to 43°25′07″ N/124°04′40″ W, thence to 43°57′48″ N/124°05′54″ W, thence to 43°28′05″ N/124°05′54″ W, thence to the beginning point.

(b) *Regulations.* (1) In accordance with the general regulations in Section 165.23 of this part, no person or vessel may enter or remain in this zone unless authorized by the Captain of the Port, Portland or his designated representatives.

(2) Designated representative means Coast Guard Patrol Commanders, including Coast Guard coxswains, petty officers or other officers operating Coast Guard vessels and Federal, State, and local officers designated by or assisting the Captain of the Port, Portland in the enforcement of the safety zone.

(c) *Enforcement Period.* This regulation will be enforced from 8:30 p.m. until 11:30 p.m. (PDT) on May 9, 2007.

Dated: March 21, 2007.

Patrick G. Gerrity,

Captain, U.S. Coast Guard, Captain of the Port.

[FR Doc. E7–6145 Filed 4–3–07; 8:45 am]

BILLING CODE 4910–15–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 174

[EPA–HQ–OPP–2006–0783; FRL–8120–5]

Bacillus thuringiensis Vip3Aa20 Protein and the Genetic Material Necessary for its Production in Corn; Temporary Exemption From the Requirement of a Tolerance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes a temporary exemption from the requirement of a tolerance for residues of the *Bacillus thuringiensis* Vip3Aa20 protein and the genetic material necessary for its production in corn when applied or/used as a plant-incorporated protectant. Syngenta Seeds, Inc. submitted a petition to EPA under the Federal Food, Drug, and Cosmetic Act (FFDCA), as amended by the Food Quality Protection Act of 1996 (FQPA), requesting the temporary tolerance exemption. This regulation eliminates the need to establish a maximum permissible level for residues of *Bacillus thuringiensis* Vip3Aa20 protein and the genetic material necessary for its production in corn when applied or/used as a plant-incorporated protectant on field corn, sweet corn, and popcorn. The temporary tolerance exemption expires on March 31, 2008.

DATES: This regulation is effective April 4, 2007. Objections and requests for hearings must be received on or before June 4, 2007, and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: EPA has established a docket for this action under docket identification (ID) number EPA–HQ–OPP–2006–0783. To access the electronic docket, go to *http://www.regulations.gov*, select ''Advanced Search,'' then ''Docket Search.'' Insert the docket ID number where indicated and select the ''Submit'' button. Follow the instructions on the regulations.gov web site to view the docket index or access available documents. All documents in the docket are listed in the docket index available in regulations.gov. 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 in the electronic docket at *http://www.regulations.gov*, or, if only available in hard copy, at the OPP Regulatory Public Docket in Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. The Docket Facility is open from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The Docket telephone number is (703) 305–5805.

FOR FURTHER INFORMATION CONTACT: Alan Reynolds, Biopesticides and Pollution Prevention Division (7511P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: (703) 605–0515; e-mail address: *reynolds.alan@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. Potentially affected entities may include, but are not limited to:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

This listing is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in this unit could also be affected. The North American Industrial Classification System (NAICS) codes have been provided to assist you and others in determining whether this action might apply to certain entities. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed under **FOR FURTHER INFORMATION CONTACT**.

B. How Can I Access Electronic Copies of this Document?

In addition to accessing an electronic copy of this **Federal Register** document through the electronic docket at *http://www.regulations.gov*, you may access this ''**Federal Register**'' document electronically through the EPA Internet under the ''**Federal Register**'' listings at *http://www.epa.gov/fedrgstr*. You may also access a frequently updated electronic version of 40 CFR part 174 through the Government Printing Office's pilot e-CFR site at *http://www.gpoaccess.gov/ecfr*.

C. Can I File an Objection or Hearing Request?

Under section 408(g) of the FFDCA, as amended by the FQPA, any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. The EPA procedural regulations which govern the submission of objections and requests for hearings appear in 40 CFR part 178. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA–HQ–OPP–2006–0783 in the subject line on the first page of your submission. All requests must be in writing, and must be mailed or delivered to the Hearing Clerk on or before June 4, 2007.

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing that does not contain any CBI for inclusion in the public docket that is described in **ADDRESSES**. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit your copies, identified by docket ID number EPA–HQ–OPP–2006–0783, by one of the following methods.

- *Federal eRulemaking Portal*: *http://www.regulations.gov*. Follow the on-line instructions for submitting comments.
- *Mail*: Office of Pesticide Programs (OPP) Regulatory Public Docket (7502P), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001.
- *Delivery*: OPP Regulatory Public Docket (7502P), Environmental Protection Agency, Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. Deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays). Special arrangements should be made for deliveries of boxed information. The Docket telephone number is (703) 305–5805.

II. Background and Statutory Findings

In the **Federal Register** of November 1, 2006 (71 FR 64269) (FRL–8095–4), EPA issued a notice pursuant to section 408(d)(3) of the FFDCA, 21 U.S.C. 346a(d)(3), announcing the filing of a pesticide tolerance petition (PP 6G7091) by Syngenta Seeds, Inc., P.O. Box 12257, Research Triangle Park, NC 27709. The petition requested that 40 CFR part 174 be amended by establishing a temporary exemption from the requirement of a tolerance for residues of the *Bacillus thuringiensis* Vip3Aa20 protein and the genetic material necessary for its production in corn when applied or used as a plant-incorporated protectant on field corn, sweet corn, and popcorn. This notice included a summary of the petition prepared by the petitioner, Syngenta Seeds, Inc. One comment was received in response to the notice of filing. The commenter objected to an exemption from the requirement of tolerance and expressed opposition to genetic alterations. The Agency understands the commenter's concerns and recognizes that some individuals believe that genetically modified crops and food should be completely banned. However, pursuant to its authority under the FFDCA, EPA conducted a comprehensive assessment of the Vip3Aa20 protein and the genetic material necessary for its production in corn, including a review of acute oral toxicity data and amino acid sequence comparisons to known toxins and allergens. In addition, data were reviewed that demonstrate that the Vip3Aa20 protein is rapidly degraded by gastric fluid *in vitro*, is not glycosylated, and is present in low levels in corn tissue. Based on these data, EPA concluded that there is a reasonable certainty that no harm will result from dietary exposure to this protein as expressed in genetically modified corn. Thus, under the standard in FFDCA section 408(c)(2), a tolerance exemption is appropriate.

Section 408(c)(2)(A)(i) of the FFDCA allows EPA to establish an exemption from the requirement for a tolerance (the legal limit for a pesticide chemical residue in or on a food) only if EPA determines that the exemption is ''safe.'' Section 408(c)(2)(A)(ii) of the FFDCA defines ''safe'' to mean that ''there is a reasonable certainty that no harm will result from aggregate exposure to the pesticide chemical residue, including all anticipated dietary exposures and all other exposures for which there is reliable information.'' This includes exposure through drinking water and in residential settings, but does not include occupational exposure. Pursuant to section 408(c)(2)(B), in establishing or maintaining in effect an exemption from the requirement of a tolerance, EPA must take into account the factors set forth in section 408(b)(2)(C), which requires EPA to give special consideration to exposure of infants and children to the pesticide chemical residue in establishing a tolerance and to ''ensure that there is a reasonable certainty that no harm will result to infants and children from aggregate exposure to the pesticide chemical residue * * *.'' Additionally, section 408(b)(2)(D) of the FFDCA requires that the Agency consider ''available information concerning the cumulative effects of a particular pesticide's residues'' and ''other substances that have a common mechanism of toxicity.''

EPA performs a number of analyses to determine the risks from aggregate exposure to pesticide residues. First, EPA determines the toxicity of pesticides. Second, EPA examines exposure to the pesticide through food, drinking water, and through other exposures that occur as a result of pesticide use in residential settings.

III. Toxicological Profile

Consistent with section 408(b)(2)(D) of the FFDCA, EPA has reviewed the available scientific data and other relevant information in support of this action and considered its validity, completeness and reliability, and the relationship of this information to human risk. EPA has also considered available information concerning the variability of the sensitivities of major identifiable subgroups of consumers, including infants and children.

Data have been submitted demonstrating a lack of mammalian toxicity at high levels of exposure to the pure (microbially-expressed) Vip3Aa20 protein. These data demonstrate the safety of Vip3Aa20 at levels well above maximum possible exposure levels that are reasonably anticipated in the crops. This is similar to the Agency position regarding toxicity and the requirement of residue data for the microbial *Bacillus thuringiensis* products from which this plant-incorporated protectant was derived (See 40 CFR 158.740(b)(2)(i)). For microbial products, the need for Tier II and III toxicity testing and residue data to verify the observed effects and clarify the source of these effects is triggered only by significant acute effects in studies such as the mouse oral toxicity study.

In order to clarify the discussion that follows in the remainder of this Final Rule, it is necessary to distinguish the various Vip3A designations that are used. Vip3Aa20 is the designation applicable to Vip3A protein expressed in corn. Vip3Aa19 is the designation applicable to Vip3A protein expressed in cotton. Because the Agency has determined that both Vip3Aa19 and Vip3Aa20 are functionally equivalent, the Agency in establishing this temporary tolerance exemption for Vip3Aa20 expressed in corn has relied on data and analysis specifically developed for Vip3Aa20, as well as on data and analysis specifically developed for Vip3Aa19. A separate temporary exemption from the requirement of tolerance already has been established for Vip3Aa19 as expressed in cotton (71 FR 24582; 40 CFR 174.452).)

An acute oral toxicity study was submitted for the Vip3Aa19 protein. Male and female mice (16 of each) were dosed with 3,675 milligrams/kilograms bodyweight (mg/kg bwt) of Vip3Aa19 protein. All mice survived the study, gained weight, had no test material-related clinical signs, and had no test material-related findings at necropsy. This acute oral toxicity data also supports the prediction that the Vip3Aa20 protein would be non-toxic to humans.

When proteins are toxic, they are known to act via acute mechanisms and at very low dose levels (Sjoblad, Roy D., *et al.* 1992). Therefore, since no effects were shown to be caused by the plant-incorporated protectants, even at relatively high dose levels, the Vip3Aa20 protein is not considered toxic. Amino acid sequence comparisons showed no similarity between the Vip3Aa20 protein and known toxic proteins available in public protein data bases. According to the Codex Alimintarius guidelines, the assessment of potential toxicity also includes stability to heat (FAO/WHO Standards Programme, 2001). A heat lability study demonstrated that Vip3Aa19 is inactivated against Fall Armyworms (FAW), when heated to 55 °C for 30 minutes.

Since Vip3Aa20 is a protein, allergenic sensitivities were considered. Currently, no definitive tests exist for determining the allergenic potential of novel proteins. Therefore, EPA uses a weight-of-the-evidence approach where the following factors are considered: Source of the trait; amino acid sequence similarity with known allergens; prevalence in food; and biochemical properties of the protein, including *in vitro* digestibility in simulated gastric fluid (SGF), and glycosylation. Current scientific knowledge suggests that common food allergens tend to be resistant to degradation acids and

proteases; may be glycosylated; and present at high concentrations in the food.

Data have been submitted that demonstrate that the Vip3A from recombinant maize (LPPACHA–0199) and *E. coli* (VIP3A–0100) proteins are rapidly degraded by gastric fluid *in vitro*. (VIP3A–0100 refers to a microbially-expressed Vip3A that has been shown to be the equivalent of the plant-expressed Vip3A protein.) In a solution of simulated gastric fluid (containing pepsin) and either 80 microliters (µL) of LPPACHA–0199 or 320 µL of VIP3A–0100 test protein, both were shown to be susceptible to pepsin degradation. These data support the conclusion that Vip3A proteins expressed in transgenic plants will be readily digested as a conventional dietary protein under typical mammalian gastric conditions. Further data demonstrate that Vip3Aa20 is not glycoslylated and a comparison of amino acid sequences of known allergens uncovered no evidence of any homology with Vip3Aa20, even at the level of 8 contiguous amino acid residues. Preliminary data of the quantification of Vip3Aa20 protein in various maize tissues were also submitted. This data demonstrated that mean Vip3Aa20 concentrations in corn kernels ranged from approximately 24.6 - 40.3 micrograms (µg) Vip3Aa20/dry weight, representing approximately 0.003% of the total protein in grain (assuming that corn grain contains 10% total protein by weight). Therefore, Vip3Aa20 is present in low levels in corn tissue and the protein expression is much lower than the amounts of allergen protein found in commonly allergenic foods. In those foods, the allergens can be 10 to 50% of the total protein found.

Therefore, the potential for the Vip3Aa20 protein to be a food allergen is minimal. As noted above, toxic proteins typically act as acute toxins with low dose levels. Therefore, since no effects were shown to be caused by this plant-incorporated protectant, even at relatively high dose levels, the Vip3Aa20 protein is not considered toxic.

IV. Aggregate Exposures

In examining aggregate exposure, section 408 of the FFDCA directs EPA to consider available information concerning exposures from the pesticide residues in food and all other non-occupational exposures, including drinking water from ground water or surface water, and exposure through pesticide use in gardens, lawns, or buildings (residential and other indoor uses).

The Agency has considered available information on the aggregate exposure levels of consumers (and major identifiable subgroups of consumers) to the pesticide chemical residue and to other related substances. These considerations include dietary exposure under the tolerance exemption and all other tolerances or exemptions in effect for the plant-incorporated protectant chemical residue, and exposure from non-occupational sources. Exposure via the skin or inhalation is not likely since the plant-incorporated protectant is contained within plant cells, which essentially eliminates these exposure routes or reduces these exposure routes to negligible. The amino acid homology assessment revealed no similarities to known aeroallergens, indicating that Vip3A has a low potential to be an inhalation allergen. It has been demonstrated that there is no evidence of occupationally related respiratory symptoms, based on a health survey on migrant workers after exposure to *Bt* pesticides (Berstein *et al.* 1999), which provides further evidence of the negligible respiratory risks of Bt plant-incorporated protectants. Exposure via residential or lawn use to infants and children is also not expected because the use sites for the Vip3Aa20 protein are all agricultural for control of insects. Oral exposure, at very low levels, may occur from ingestion of processed corn products and, theoretically, drinking water.

However, oral toxicity testing done at a dose in excess of 3 gm/kg showed no adverse effects. Furthermore, the expected dietary exposure from both cotton and corn are several orders of magnitude lower than the amounts of Vip3Aa20 protein shown to have no toxicity. Therefore, even if negligible aggregate exposure should occur, the Agency concludes that such exposure would present no harm due to the lack of mammalian toxicity and the rapid digestibility demonstrated for the Vip3Aa20 proteins.

V. Cumulative Effects

Pursuant to FFDCA section 408(b)(2)(D)(v), EPA has considered available information on the cumulative effects of such residues and other substances that have a common mechanism of toxicity. These considerations include the cumulative effects on infants and children of such residues and other substances with a common mechanism of toxicity. Because there is no indication of mammalian toxicity, the Agency concludes that there are no cumulative effects arising from Vip3Aa20 protein residues in corn.

VI. Determination of Safety for U.S. Population, Infants and Children

A. Toxicity and Allergenicity Conclusions

The data submitted and cited regarding potential health effects for the Vip3Aa20 protein include the characterization of the expressed Vip3Aa20 protein in corn, as well as the acute oral toxicity, heat stability, and *in vitro* digestibility of the proteins. The results of these studies were determined applicable to evaluate human risk, and the validity, completeness, and reliability of the available data from the studies were considered.

Adequate information was submitted to show that the Vip3A protein test material derived from microbial cultures (designated VIP3A–0100) was biochemically and functionally similar to the Vip3Aa20 protein expressed in corn. Microbially produced protein was chosen in order to obtain sufficient material for testing.

The acute oral toxicity data submitted supports the prediction that the Vip3Aa20 protein would be non-toxic to humans. As mentioned above, when proteins are toxic, they are known to act via acute mechanisms and at very low dose levels (Sjoblad, Roy D., *et al.* 1992). Since no effects were shown to be caused by Vip3Aa20 protein, even at relatively high dose levels (3,675 mg Vip3Aa19/kg bwt), the Vip3Aa20 protein is not considered toxic. This is similar to the Agency position regarding toxicity and the requirement of residue data for the microbial *Bacillus thuringiensis* products from which this plant-incorporated protectant was derived. (See 40 CFR 158.740(b)(2)(i)). Moreover, Vip3Aa20 showed no sequence similarity to any known toxin.

Protein residue chemistry data for Vip3Aa20 were not required for a human health effects assessment of the subject plant-incorporated protectant ingredients because of the lack of mammalian toxicity. However, preliminary data (that were submitted with administrative materials for an Experimental Use Permit application for corn expressing the Vip3Aa20 protein) demonstrated low levels of Vip3Aa20 in corn tissues with less than 40 µg Vip3Aa20 protein/gram dry weight in kernels and less than 75 µg Vip3Aa20 protein/gram dry weight of whole corn plant.

Since Vip3Aa20 is a protein, its potential allergenicity is also considered as part of the toxicity assessment. Information considered as part of the

allergenicity assessment included data demonstrating that the Vip3Aa20 protein came from a *Bacillus thuringiensis* which is not a known allergenic source, showed no sequence similarity to known allergens, was readily degraded by pepsin, and was not glycosylated when expressed in the plant. Therefore, there is a reasonable certainty that the Vip3Aa20 protein will not be an allergen.

Neither available information concerning the dietary consumption patterns of consumers (and major identifiable subgroups of consumers including infants and children), nor safety factors that are generally recognized as appropriate for the use of animal experimentation data were evaluated. The lack of mammalian toxicity at high levels of exposure to the Vip3Aa20 protein, as well as the minimal potential to be a food allergen, demonstrate the safety of Vip3Aa20 at levels well above possible maximum exposure levels anticipated in the crop.

The genetic material necessary for the production of the plant-incorporated protectant active ingredients are the nucleic acids (DNA, RNA) which comprise genetic material encoding these proteins and their regulatory regions. The genetic material (DNA, RNA) necessary for the production of Vip3Aa20 protein already are exempted from the requirement of a tolerance under a blanket exemption for all nucleic acids (40 CFR 174.475).

B. Infants and Children Risk Conclusions

FFDCA section 408(b)(2)(C) provides that EPA shall assess the available information about consumption patterns among infants and children, special susceptibility of infants and children to pesticide chemical residues, and the cumulative effects on infants and children of the residues and other substances with a common mechanism of toxicity.

In addition, FFDCA section 408(b)(2)(C) also provides that EPA shall apply an additional tenfold margin of safety for infants and children in the case of threshold effects to account for prenatal and postnatal toxicity and the completeness of the data base, unless EPA determines that a different margin of safety will be safe for infants and children.

In this instance, based on all the available information, the Agency concludes that there is a finding of no toxicity for the Vip3Aa20 protein and the genetic material necessary for its production in corn. Because there are no threshold effects of concern, the Agency has determined that the additional tenfold margin of safety is not necessary to protect infants and children. Further, the provisions of consumption patterns, special susceptibility, and cumulative effects do not apply.

C. Overall Safety Conclusion

There is a reasonable certainty that no harm will result to the U.S. population, including infants and children, from aggregate exposure to residues of the Vip3Aa20 protein and the genetic material necessary for its production in corn, when it is applied or/used in accordance with good agricultural practices on field corn, sweet corn, and popcorn. This includes all anticipated dietary exposures and all other exposures for which there is reliable information. The Agency has arrived at this conclusion because, as previously discussed, no toxicity to mammals has been observed, nor has there been any indication of allergenicity potential for this plant-incorporated protectant.

VII. Other Considerations

A. Endocrine Disruptors

The pesticidal active ingredient is a protein, derived from sources that are not known to exert an influence on the endocrine system. Therefore, the Agency is not requiring information on the endocrine effects of the plant-incorporated protectant at this time.

B. Analytical Method

A method for extraction and enzyme linked immunosorbent assay (ELISA) analysis of Vip3Aa20 protein in corn has been submitted and is under review by the Agency.

C. Codex Maximum Residue Level

No Codex maximum residue levels exist for the plant-incorporated protectant *Bacillus thuringiensis* Vip3Aa20 protein and the genetic material necessary for its production in corn.

VIII. Statutory and Executive Order Reviews

This final rule establishes an exemption from the requirement of a tolerance under section 408(d) of FFDCA in response to a petition submitted to the Agency. The Office of Management and Budget (OMB) has exempted these types of actions from review under Executive Order 12866, entitled *Regulatory Planning and Review* (58 FR 51735, October 4, 1993). Because this rule has been exempted from review under Executive Order 12866, this rule is not subject to Executive Order 13211, *Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use* (66 FR 28355, May 22, 2001) or Executive Order 13045, entitled *Protection of Children from Environmental Health Risks and Safety Risks* (62 FR 19885, April 23, 1997). This final rule does not contain any information collections subject to OMB approval under the Paperwork Reduction Act (PRA), 44 U.S.C. 3501 *et seq.*, nor does it require any special considerations under Executive Order 12898, entitled *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations* (59 FR 7629, February 16, 1994).

Since tolerances and exemptions that are established on the basis of a petition under section 408(d) of FFDCA, such as the exemption in this final rule, do not require the issuance of a proposed rule, the requirements of the Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*) do not apply.

This final rule directly regulates growers, food processors, food handlers and food retailers, not States or tribes, nor does this action alter the relationships or distribution of power and responsibilities established by Congress in the preemption provisions of section 408(n)(4) of FFDCA. As such, the Agency has determined that this action will not have a substantial direct effect on States or tribal governments, on the relationship between the national government and the States or tribal governments, or on the distribution of power and responsibilities among the various levels of government or between the Federal Government and Indian tribes. Thus, the Agency has determined that Executive Order 13132, entitled *Federalism* (64 FR 43255, August 10, 1999) and Executive Order 13175, entitled *Consultation and Coordination with Indian Tribal Governments* (65 FR 67249, November 6, 2000) do not apply to this rule. In addition, This rule does not impose any enforceable duty or contain any unfunded mandate as described under Title II of the Unfunded Mandates Reform Act of 1995 (UMRA) (Public Law 104–4).

This action does not involve any technical standards that would require Agency consideration of voluntary consensus standards pursuant to section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, section 12(d) (15 U.S.C. 272 note).

IX. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report to each House of

the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of this final rule in the **Federal Register**. This final rule is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 174

Environmental protection, Administrative practice and procedure, Agricultural commodities, Pesticides and pests, Reporting and recordkeeping requirements.

Dated: March 23, 2007.

James Jones,

Director, Office of Pesticide Programs.

■ Therefore, 40 CFR chapter I is amended as follows:

PART 174—AMENDED

■ 1. The authority citation for part 174 continues to read as follows:

Authority: 21 U.S.C. 321(q), 346a and 371.

■ 2. Section 174.458 is added to subpart W to read as follows:

§ 174.458 Bacillus thuringiensis Vip3Aa20 protein and the genetic material necessary for its production in corn; temporary exemption from the requirement of a tolerance.

Residues of *Bacillus thuringiensis* Vip3Aa20 protein in corn are temporarily exempt from the requirement of a tolerance when used as a plant-incorporated protectant in the food and feed commodities of corn; corn, field; corn, sweet; corn, pop. This temporary exemption from the requirement of tolerance will permit the use of the food commodities in this paragraph when treated in accordance with the provisions of the experimental use permit 67979–EUP–6, which is being issued in accordance with the provisions of the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), as amended (7 U.S.C. 136). This temporary exemption from the requirement of a tolerance expires and is revoked March 31, 2008; however, if the experimental use permit is revoked, or if any experience with or scientific data on this pesticide indicate that the temporary tolerance exemption is not safe, this temporary exemption from the requirement of a tolerance may be revoked at any time.

[FR Doc. E7–6256 Filed 4–3–07; 8:45 am]

BILLING CODE 6560–50–S

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2006–0731; FRL–8120–4]

Diphenylamine; Pesticide Tolerance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes a tolerance for residues of diphenylamine in or on pear. Interregional Research Project Number 4 (IR-4) requested this tolerance under the Federal Food, Drug, and Cosmetic Act (FFDCA).

DATES: This regulation is effective April 4, 2007. Objections and requests for hearings must be received on or before June 4, 2007, and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: EPA has established a docket for this action under docket identification (ID) number EPA-HQ-OPP-2006-0731. To access the electronic docket, go to *http://www.regulations.gov*, select ''Advanced Search,'' then ''Docket Search.'' Insert the docket ID number where indicated and select the ''Submit'' button. Follow the instructions on the regulations.gov web site to view the docket index or access available documents. All documents in the docket are listed in the docket index available in regulations.gov. 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 in the electronic docket at *http://www.regulations.gov*,or, if only available in hard copy, at the OPP Regulatory Public Docket in Rm. S-4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. The Docket Facility is open from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The Docket telephone number is (703) 305-5805.

FOR FURTHER INFORMATION CONTACT: Shaja R. Brothers, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460-0001; telephone number: (703) 308-3194; e-mail address: *brothers.shaja@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. Potentially affected entities may include, but are not limited to those engaged in the following activities:

- Crop production (NAICS code 111), e.g., agricultural workers; greenhouse, nursery, and floriculture workers; farmers.
- Animal production (NAICS code 112), e.g., cattle ranchers and farmers, dairy cattle farmers, livestock farmers.
- Food manufacturing (NAICS code 311), e.g., agricultural workers; farmers; greenhouse, nursery, and floriculture workers; ranchers; pesticide applicators.
- Pesticide manufacturing (NAICS code 32532), e.g., agricultural workers; commercial applicators; farmers; greenhouse, nursery, and floriculture workers; residential users.

This listing is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in this unit could also be affected. The North American Industrial Classification System (NAICS) codes have been provided to assist you and others in determining whether this action might apply to certain entities. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed under **FOR FURTHER INFORMATION CONTACT**.

B. How Can I Access Electronic Copies of this Document?

In addition to accessing an electronic copy of this ''**Federal Register**'' document through the electronic docket at *http://www.regulations.gov*, you may access this **Federal Register** document electronically through the EPA Internet under the ''**Federal Register**'' listings at *http://www.epa.gov/fedrgstr*. You may also access a frequently updated electronic version of EPA's tolerance regulations at 40 CFR part 180 through the Government Printing Office's pilot e-CFR site at *http://www.gpoaccess.gov/ecfr*.

C. Can I File an Objection or Hearing Request?

Under section 408(g) of the FFDCA, any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in

accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA-HQ-OPP-2006-0731 in the subject line on the first page of your submission. All requests must be in writing, and must be mailed or delivered to the Hearing Clerk as required by 40 CFR part 178 on or before June 4, 2007.

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing that does not contain any CBI for inclusion in the public docket that is described in **ADDRESSES**. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit this copy, identified by docket ID number EPA-HQ-OPP-2006-0731, by one of the following methods:

• *Federal eRulemaking Portal*: *http://www.regulations.gov*. Follow the on-line instructions for submitting comments.

• *Mail*: Office of Pesticide Programs (OPP) Regulatory Public Docket (7502P), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460-0001.

• *Delivery*: OPP Regulatory Public Docket (7502P), Environmental Protection Agency, Rm. S-4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. Deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays). Special arrangements should be made for deliveries of boxed information. The Docket telephone number is (703) 305-5805.

II. Petition for Tolerance and Proposed Rule

The Interregional Research Project Number 4 (IR-4) submitted a petition (PP# 0E6107) for a tolerance for the pesticide diphenylamine under section 408 of the FFDCA, 21 U.S.C. 346a. Specifically, the petition requested that 40 CFR 180.190 be amended by establishing a tolerance for residues of the plant growth regulator diphenylamine, in or on pear (post harvest) at 5.0 parts per million (ppm). However, neither IR-4 nor Atomchem North American Incorporated, the registrant, submitted all required elements of a petition in support of establishing a tolerance. Because the petition was incomplete, EPA did not publish a Notice of Filing for the petition. Instead, in the **Federal Register** of December 6, 2006 (71 FR 70703) (FRL–8104–1), EPA issued a proposed rule pursuant to section 408(e) of FFDCA, 21 U.S.C. 346a(e). The proposed rule included EPA's explanation of why the proposed diphenylamine tolerance regulation met the safety standard.

The Northwest Horticulture Council submitted two comments in favor of the establishment of diphenylamine on pear.

There was also a comment submitted by a private citizen who opposed the authorization to sell to any pesticide that leaves a residue on food. The Agency has previously responded to this commenter's claims regarding the validity of use animal testing to determine a pesticide's potential toxicity. Refer to **Federal Register** of (70 FR 1349, January 7, 2005). This commenter also claimed the Agency was ''negligent'' for only conducting 90–day testing on rats. The commenter is mistaken, however, because EPA examined other rat studies involving lifetime exposure and multiple generations of rats. (71 FR 70703) (FRL–7691–4), December 6, 2006).

The final comment opposed the proposed regulation simply on the grounds that there are ''too many bugs'' and too many pesticide regulations. This comment supplied no rationale or supporting information and thus no response is warranted.

III. Action on Tolerance Petition and Proposed Regulation

Based on the rationale and findings set forth in the proposed rule, a tolerance is established for the residues of diphenylamine in or on pear at 5.0 ppm.

IV. Statutory and Executive Order Reviews

This final rule establishes a tolerance under section 408(d) of FFDCA in response to a petition submitted to the Agency. The Office of Management and Budget (OMB) has exempted these types of actions from review under Executive Order 12866, entitled *Regulatory Planning and Review* (58 FR 51735, October 4, 1993). Because this rule has been exempted from review under Executive Order 12866, this rule is not subject to Executive Order 13211, *Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use* (66 FR 28355, May 22, 2001) or Executive Order 13045, entitled *Protection of Children from Environmental Health Risks and Safety Risks* (62 FR 19885, April 23, 1997). This final rule does not contain any information collections subject to OMB approval under the Paperwork Reduction Act (PRA), 44 U.S.C. 3501 *et seq.*, nor does it require any special considerations under Executive Order 12898, entitled *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations* (59 FR 7629, February 16, 1994).

Pursuant to the Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*), the Agency hereby certifies that this proposed action will not have significant negative economic impact on a substantial number of small entities. Establishing a pesticide tolerance or an exemption from the requirement of a pesticide tolerance is, in effect, the removal of a regulatory restriction on pesticide residues in food and thus such an action will not have any negative economic impact on any entities, including small entities.

This rule directly regulates growers, food processors, food handlers and food retailers, not States or tribes, nor does this action alter the relationships or distribution of power and responsibilities established by Congress in the preemption provisions of section 408(n)(4) of FFDCA. As such, the Agency has determined that this action will not have a substantial direct effect on States or tribal governments, on the relationship between the national government and the States or tribal governments, or on the distribution of power and responsibilities among the various levels of government or between the Federal Government and Indian tribes. Thus, the Agency has determined that Executive Order 13132, entitled *Federalism* (64 FR 43255, August 10, 1999) and Executive Order 13175, entitled *Consultation and Coordination with Indian Tribal Governments* (65 FR 67249, November 6, 2000) do not apply to this rule. In addition, This rule does not impose any enforceable duty or contain any unfunded mandate as described under Title II of the Unfunded Mandates Reform Act of 1995 (UMRA) (Public Law 104-4).

This action does not involve any technical standards that would require Agency consideration of voluntary consensus standards pursuant to section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104-113, section 12(d) (15 U.S.C. 272 note).

V. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S.

Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of this final rule in the **Federal Register**. This final rule is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 180

Environmental protection, Administrative practice and procedure, Agricultural commodities, Pesticides and pests, Reporting and recordkeeping requirements.

Dated: March 21, 2007.

Donald R. Stubbs,

Acting Director, Registration Division, Office of Pesticide Programs.

■ Therefore, 40 CFR chapter I is amended as follows:

PART 180—[AMENDED]

■ 1. The authority citation for part 180 continues to read as follows:

Authority: 21 U.S.C. 321(q), 346a and 371.

■ 2. Section 180.190 is amended by alphabetically adding the following commodity to the table in paragraph (a) to read as follows:

§ 180.190 Diphenylamine; tolerances for residues.

(a) * * *

Commodity	Parts per million
* * * * *	
Pear (post harvest)	5.0
* * * * *	

* * * * *

[FR Doc. E7–5804 Filed 4–3–07; 8:45 am]

BILLING CODE 6560–50–S

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[DA 07–1349; MB Docket No. 02–177; RM–10489]

Radio Broadcasting Services; Milano, TX

AGENCY: Federal Communications Commission.

ACTION: Final rule; dismissal of petition for reconsideration.

SUMMARY: The staff approves the withdrawal of a petition for reconsideration in this FM allotment rulemaking proceeding and finds no reason for further consideration of the matters raised therein. *See* **SUPPLEMENTARY INFORMATION.**

FOR FURTHER INFORMATION CONTACT: Andrew J. Rhodes, Media Bureau, (202) 418–2180.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's *Memorandum Opinion and Order*, MB Docket No. 02–177, adopted March 16, 2007, and released March 20, 2007. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC Reference Information Center (Room CY–A257), 445 12th Street, SW., Washington, DC 20554. The complete text of this decision may also be purchased from the Commission's copy contractor, Best Copy and Printing, Inc., Portals II, 445 12th Street, SW., Room CY–B402, Washington, DC 20554, telephone 1–800–378–3160 or *http://www.BCPIWEB.com.*

The *Report and Order* in this proceeding dismissed a counterproposal in this rulemaking proceeding filed by Roy. E. Henderson, requesting the upgrade and reallotment of his Station KLTR(FM) from Channel 297A, Caldwell, Texas, to Channel 297C3 at Bedias, Texas. The counterproposal was dismissed because it was technically defective. The withdrawal of the petition for reconsideration complies with Section 1.420(j) of the Commission's rules because Henderson has documented that he has not and will not receive any consideration in exchange for the withdrawal of his petition. *See* 69 FR 34114 (June 18, 2004).

This document is not subject to the Congressional Review Act. (The Commission, is, therefore, not required to submit a copy of this Memorandum Opinion and Order to GAO, pursuant to the Congressional Review Act, see 5 U.S.C. 801(a)(1)(A) because the petition for reconsideration was dismissed).

Federal Communications Commission.

John A. Karousos,

Assistant Chief, Audio Division, Media Bureau.

[FR Doc. E7–6225 Filed 4–3–07; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[FCC 06–117]

National Broadcast Television Ownership Rules

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: In this document, the Commission conforms its rules to comply with the Consolidated Appropriations Act, 2004 (Appropriations Act). The Appropriations Act, among other things, directs the Commission to modify the national television ownership limit to specify 39 percent as the maximum aggregate national audience reach of any single television station owner. The Appropriations Act also adds a new section to the Telecommunications Act of 1996, which the Commission now implements.

DATES: Effective May 4, 2007.

FOR FURTHER INFORMATION CONTACT: Mania Baghdadi, Industry Analysis Division, Media Bureau, Federal Communications Commission, (202) 418–2330. Press inquiries should be directed to Clyde Ensslin, (202) 418–0506.

SUPPLEMENTARY INFORMATION:

Initial Paperwork Reduction Act of 1995 Analysis

This document does not contain any information collection requirements subject to the Paperwork Reduction Act of 1995, Public Law 104–13. In addition, it does not contain any information collection burden ''for small business concerns with fewer than 25 employees,'' pursuant to the Small Business Paperwork Relief Act of 2002, Public Law 107–198, see 44 U.S.C. 3506(c)(4).

Synopsis of Order

1. On January 22, 2004, President Bush signed into law the Consolidated Appropriations Act, 2004, H.R. 2673 (''the Appropriations Act'').[1] Section

[1] Consolidated Appropriations Act, 2004, Public Law 108–199, § 629, 118 Stat. 3 (2004).

629(1) of the Appropriations Act amends section 202(c) of the Telecommunications Act of 1996 (''Telecommunications Act'') to direct the Commission to modify the national television ownership limit, contained in section 73.3555 of the Commission's rules,[2] to specify 39 percent as the maximum aggregate national audience reach of any single television station owner.[3] The Appropriations Act also adds to the Telecommunications Act a new section 202(c)(3), which states:

(3) DIVESTITURE—A person or entity that exceeds the 39 percent national audience reach limitation for television stations in paragraph (1)(B) through grant, transfer, or assignment of an additional license for a commercial television broadcast station shall have not more than 2 years after exceeding such limitation to come into compliance with such limitation. This divestiture requirement shall not apply to persons or entities that exceed the 39 percent national audience reach limitation through population growth.[4]

With this Order, the Commission conforms its rules to these provisions. Section 73.3555(d) will be redesignated as section 73.3555(e), section 73.3555(e)(1) is revised to reflect the changes directed by section 202(c)(1) of the Telecommunications Act, as amended by the Appropriations Act, and a new section 73.3555(e)(3) is added to reflect section 202(c)(3).[5] These changes are set forth in the rule changes section of this summary.[6]

2. The Commission is revising its rules without providing prior public notice and an opportunity for comment because the rule modifications are mandated by the applicable provisions of the Appropriations Act and Telecommunications Act. The Commission finds that notice and comment procedures are unnecessary, and that this action therefore falls within the ''good cause'' exception of the Administrative Procedure Act.[7] The rule changes adopted in this Order do not involve discretionary action on the part of the Commission. Rather, they simply implement provisions of the Appropriations Act, as it amends the Telecommunications Act, which directs the Commission to revise its rules according to specific terms set forth in those laws.

Ordering Clauses

3. Accordingly, *it is ordered* that pursuant to section 629 of the Consolidated Appropriations Act, 2004, and section 202(c)(1) of the Telecommunications Act of 1996, as amended, and sections 4(i) and 303(r) of the Communications Act of 1934, as amended, 47 U.S.C. 154(i), 303(r), Part 73 of the Commission's Rules, 47 CFR part 73, *is amended.* The rule change will become effective May 4, 2007.[8]

4. The Commission will send a copy of this Order in a report to be sent to Congress and the Government Accountability Office pursuant to the Congressional Review Act, *see* 5 U.S.C. 801(a)(1)(A).

List of Subjects in 47 CFR Part 73

Television.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

Rule Changes

■ Part 73 of Title 47 of the Code of Federal Regulations is amended to read as follows:

PART 73—RADIO BROADCAST SERVICES

■ 1. The authority citation for part 73 continues to read as follows:

Authority: 47 U.S.C. 154, 303, 334, and 336.

■ 2. Section 73.3555 is amended by redesignating paragraphs (d) and (e) as paragraphs (e) and (f), add and reserve paragraph (d) and revise paragraph (e)(1) and add paragraph (e)(3) to read as follows:

* * * * *

§ 73.3555 Multiple ownership.

* * * * *

(e) * * *

National television multiple ownership rule. (1) No license for a commercial television broadcast station shall be granted, transferred or assigned to any party (including all parties under common control) if the grant, transfer or assignment of such license would result in such party or any of its stockholders, partners, members, officers or directors having a cognizable interest in television stations which have an aggregate national audience reach exceeding thirty-nine (39) percent.

* * * * *

(3) *Divestiture.* A person or entity that exceeds the thirty-nine (39) percent national audience reach limitation for television stations in paragraph (e)(1) of this section through grant, transfer, or assignment of an additional license for a commercial television broadcast station shall have not more than 2 years after exceeding such limitation to come into compliance with such limitation. This divestiture requirement shall not apply to persons or entities that exceed the 39 percent national audience reach limitation through population growth.

* * * * *

[FR Doc. E7–6162 Filed 4–3–07; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

RIN 1018–AV16

Endangered and Threatened Wildlife and Plants; Adding Four Marine Taxa to the List of Endangered and Threatened Wildlife

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Final rule.

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[2] 47 CFR 73.3555.

[3] 47 U.S.C. 202(c)(1). Prior to passage of the Appropriations Act, Section 202(c)(1) of the Telecommunications Act established a national television ownership reach limit of 35 percent, which was incorporated in Section 73.3555(e) of the Commission's rules. In the 2002 biennial ownership proceeding, the Commission raised the national television ownership limit from 35 percent to 45 percent. *2002 Biennial Regulatory Review*, 68 FR 46286, August 5, 2003 (''2002 Biennial Report and Order''), *aff'd in part, remanded in part, Prometheus Radio Project* v. *FCC*, 373 F.3d 372 (3rd Cir. 2004) (''Prometheus Order''), *cert. denied*, 13 U.S.L.W. 3466 (June 13, 2005). The rule changes adopted in the biennial ownership proceeding were stayed, however, by the U.S. Court of Appeals for the Third Circuit and, except for a partial lifting of the stay with respect to the local radio ownership rules, remain stayed pending further judicial action. *Prometheus Radio Project, et al.* v. *FCC*, No. 03–3388 (Sept. 3, 2003) (order granting stay); *Prometheus Radio Project* v. *FCC*, No. 03–3388 (3rd Cir. Sept. 3, 2004) (order partially lifting stay).

[4] 47 U.S.C. 202(c)(3).

[5] In 2003, the Commission's 2002 Biennial Report and Order eliminated the radio-television cross-ownership rule, formerly found at 47 CFR 73.3555(c). As a result, the national television ownership rule was renumbered from 47 CFR 73.3555(e)(1) to 47 CFR 73.3555(d)(1). However, the rules adopted in the 2002 Biennial Report and Order, and published in the CFR, were stayed by a court and did not go into effect. However, after the stay was applied, the new 39 percent cap was promulgated pursuant to the Appropriations Act.

[6] The current broadcast attribution rules set forth in the notes to Section 73.3555 would continue to apply to the national television ownership rule as Congress did not indicate any intent that the Commission alter them in this proceeding. The statute directs the Commission to change the audience reach limit to 39 percent and add the new divestiture provision. Neither the statute nor the legislative history indicate that Congress intended that we make any other changes to the national television ownership rule in this proceeding.

[7] *See* 5 U.S.C. 553(b)(B) (notice requirements inapplicable ''when the agency for good cause finds * * * that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest''); *Metzenbaum* v. *Federal Energy Regulatory Commission*, 675 F.2d 1282, 1291 (D.C. Cir. 1982) (agency orders that were nondiscretionary ministerial actions issued in conformity with statute were properly issued without notice and comment).

[8] *See* 5 U.S.C. 553(d).

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), are adding four marine taxa to the List of Endangered and Threatened Wildlife (List) in accordance with the Endangered Species Act of 1973, as amended. These amendments are based on previously published determinations by the National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration, Department of Commerce, which has jurisdiction for these species. These four taxa are the Southern Distinct Population Segment (DPS) of green sturgeon (*Acipenser medirostris*), staghorn (*Acropora cervicornis*) and elkhorn (*Acropora palmata*) corals, and the Southern Resident killer whale DPS (*Orcinus orca*).

DATES: This rule is effective April 4, 2007.

Applicability dates: The Southern DPS of the North American green sturgeon (*Acipenser medirostris*) listing is applicable as of June 6, 2006. The elkhorn coral (*Acropora palmata*) and staghorn coral (*Acropora cervicornis*) listing is applicable as of June 8, 2006. The Southern Resident killer whale DPS (*Orcinus orca*) listing is applicable as of February 16, 2006.

FOR FURTHER INFORMATION CONTACT: Branch of Listing, Endangered Species Program, U.S. Fish and Wildlife Service, 4401 N. Fairfax Drive, Mail Stop 420, Arlington, Virginia 22203 (703–358–2105).

SUPPLEMENTARY INFORMATION:

Background

In accordance with the Act and the Reorganization Plan No. 4 of 1970, NMFS has jurisdiction over these taxa. Under section 4(a)(2) of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*), NMFS must decide whether a species under its jurisdiction should be classified as endangered or threatened. The Service is responsible for the actual amendment of the List in 50 CFR 17.11(h).

On April 6, 2005, NMFS published a proposed rule (70 FR 17386) to list the Southern DPS of the North American green sturgeon (*Acipenser medirostris*) as threatened. During the public comment period for that proposed rule, NMFS received 32 comments. On April 7, 2006, NMFS published a final rule to list the Southern DPS of the North American green sturgeon as threatened (71 FR 17757). The listing was effective as of June 6, 2006. In that final rule, NMFS addressed all public comments received in response to the proposed rule.

On May 9, 2005, NMFS published a proposed rule (70 FR 24359) to list the elkhorn coral (*Acropora palmata*) and staghorn coral (*Acropora cervicornis*) as threatened. During the public comment period for that proposed rule, NMFS received 1,393 comments. On May 9, 2006, NMFS published a final rule to list the elkhorn and staghorn corals as threatened (71 FR 26852). The listing was effective as of June 8, 2006. In that final rule, NMFS addressed all public comments received in response to the proposed rule.

On December 22, 2004, NMFS published a proposed rule (69 FR 76673) to list the Southern Resident killer whale DPS (*Orcinus orca*) as threatened. During the public comment period for that proposed rule, NMFS received 1,326 comments. On November 18, 2005, NMFS published a final rule to list the Southern Resident killer whale DPS as threatened (70 FR 69903). The listing was effective as of February 16, 2006. In that final rule, NMFS addressed all public comments received in response to the proposed rule.

Because NMFS provided a public comment period on the proposed rules for these taxa, and because this action of the Service to amend the List in accordance with the determination by NMFS is nondiscretionary, the Service finds good cause that the notice and public comment procedures of 5 U.S.C. 553(b) are unnecessary for this action. We also find good cause under 5 U.S.C. 553(d)(3) to make this rule effective immediately. The NMFS rules extended protection under the Act to these species and listed them in 50 CFR part 224; this rule is an administrative action to add the species to the List of Endangered and Threatened Species in 50 CFR 17.11(h). The public would not be served by delaying the effective date of this rulemaking action.

For more information concerning these two listing determinations, please consult the respective rules published in the **Federal Register**.

Required Determinations

National Environmental Policy Act

The Service has determined that an Environmental Assessment, as defined under the authority of the National Environmental Policy Act of 1969, need not be prepared in connection with regulations adopted pursuant to section 4(a) of the Act. A notice outlining the Service's reasons for this determination was published in the **Federal Register** on October 25, 1983 (48 FR 49244).

Paperwork Reduction Act

The Service has examined this regulation under the Paperwork Reduction Act of 1995 and found it to contain no information collection requirements. We may not conduct or sponsor, and you are not required to respond to, a collection of information unless it displays a currently valid Office of Management and Budget (OMB) control number.

List of Subjects in 50 CFR Part 17

Endangered and threatened species, Exports, Imports, Reporting and recordkeeping requirements, Transportation.

Regulation Promulgation

■ Accordingly, part 17, subchapter B of chapter I, title 50 of the Code of Federal Regulations, is amended as set forth below:

PART 17—[AMENDED]

■ 1. The authority citation for part 17 continues to read as follows:

Authority: 16 U.S.C. 1361–1407; 16 U.S.C. 1531–1544; 16 U.S.C. 4201–4245; Pub. L. 99–625, 100 Stat. 3500, unless otherwise noted.

■ 2. Amend § 17.11(h) by:

■ a. Adding the subheading ''CORALS'' at the end of the table; and

■ b. Adding the following entries, in alphabetical order under MAMMALS, FISHES, and CORALS, respectively, to the List of Endangered and Threatened Wildlife:

§ 17.11 Endangered and threatened wildlife.

* * * * *

(h) * * *

Species		Historic range	Vertebrate population where endangered or threatened	Status	When listed	Critical habitat	Special rules
Common name	Scientific name						
MAMMALS							
*	*	*	*	*	*	*	
Whale, killer	*Orcinus orca*	Pacific Ocean	Southern Resident DPS, which consists of whales from the J, K, and L pods, wherever they are found in the wild.	E	756	NA	NA
*	*	*	*	*	*	*	
FISHES							
*	*	*	*	*	*	*	
Sturgeon, North America green.	*Acipenser medirostris.*	U.S.A. (CA)	U.S.A. (CA) Southern Distinct Population Segment, which includes all spawning populations south of the Eel River (exclusive), principally including the Sacramento River spawning population.	T	756	NA	NA
*	*	*	*	*	*	*	
CORALS							
Coral, elkhorn	*Acropora palmata* ...	U.S.A. (FL, PR, VI, Navassa); and wider Caribbean-Belize, Colombia, Costa Rica, Guatemala, Honduras, Mexico, Nicaragua, Panama, Venezuela, and all the islands of the West Indies.	N/A	T	756	NA	NA
Coral, staghorn	*Acropora cervicornis*	U.S.A. (FL, PR, VI, Navassa); and wider Caribbean-Belize, Colombia, Costa Rica, Guatemala, Honduras, Mexico, Nicaragua, Panama, Venezuela, and all the islands of the West Indies.	N/A	T	756	NA	NA

Dated: March 23, 2007.

Kenneth Stansell,

Acting Director, U.S. Fish and Wildlife Service.

[FR Doc. E7–6188 Filed 4–3–07; 8:45 am]

BILLING CODE 4310–55–P

Proposed Rules

Federal Register
Vol. 72, No. 64
Wednesday, April 4, 2007

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 TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2007–27756; Directorate Identifier 2006–NM–255–AD]

RIN 2120–AA64

Airworthiness Directives; McDonnell Douglas Model DC–8–62, DC–8–62F, DC–8–63, DC–8–63F, DC–8–72, DC–8–72F, and DC–8–73F Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to adopt a new airworthiness directive (AD) for all McDonnell Douglas Model DC–8–62, DC–8–62F, DC–8–63, DC–8–63F, DC–8–72, DC–8–72F, and DC–8–73F airplanes. This proposed AD would require deactivating certain components (the sump heater, scavenge valve, and scavenge pump) of the center wing fuel tank. This proposed AD results from fuel system reviews conducted by the manufacturer. We are proposing this AD to prevent certain conditions related to these components, which could lead to a possible ignition source in the fuel tank and a potential fire or explosion.

DATES: We must receive comments on this proposed AD by May 21, 2007.

ADDRESSES: Use one of the following addresses to submit comments on this proposed AD.

- *DOT Docket Web site:* Go to *http://dms.dot.gov* and follow the instructions for sending your comments electronically.
- *Government-wide rulemaking Web site:* Go to *http://www.regulations.gov* and follow the instructions for sending your comments electronically.
- *Mail:* Docket Management Facility, U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, room PL–401, Washington, DC 20590.
- *Fax:* (202) 493–2251.
- *Hand Delivery:* Room PL–401 on the plaza level of the Nassif Building, 400 Seventh Street, SW., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Contact Boeing Commercial Airplanes, Long Beach Division, 3855 Lakewood Boulevard, Long Beach, California 90846, Attention: Data and Service Management, Dept. C1–L5A (D800–0024), for the service information identified in this proposed AD.

FOR FURTHER INFORMATION CONTACT: Serj Harutunian, Aerospace Engineer, Propulsion Branch, ANM–140L, FAA, Los Angeles Aircraft Certification Office, 3960 Paramount Boulevard, Lakewood, California 90712–4137; telephone (562) 627–5254; fax (562) 627–5210.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to submit any relevant written data, views, or arguments regarding this proposed AD. Send your comments to an address listed in the **ADDRESSES** section. Include the docket number ''FAA–2007–27756; Directorate Identifier 2006–NM–255–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of the proposed AD. We will consider all comments received by the closing date and may amend the proposed AD in light of those comments.

We will post all comments we receive, without change, to *http://dms.dot.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact with FAA personnel concerning this proposed AD. Using the search function of that Web site, anyone can find and read the comments in any of our dockets, including the name of the individual who sent the comment (or signed the comment on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477–78), or you may visit *http://dms.dot.gov.*

Examining the Docket

You may examine the AD docket on the Internet at *http://dms.dot.gov,* or in person at the Docket Management Facility office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Docket Management Facility office (telephone (800) 647–5227) is located on the plaza level of the Nassif Building at the DOT street address stated in the **ADDRESSES** section. Comments will be available in the AD docket shortly after the Docket Management System receives them.

Discussion

The FAA has examined the underlying safety issues involved in fuel tank explosions on several large transport airplanes, including the adequacy of existing regulations, the service history of airplanes subject to those regulations, and existing maintenance practices for fuel tank systems. As a result of those findings, we issued a regulation titled ''Transport Airplane Fuel Tank System Design Review, Flammability Reduction and Maintenance and Inspection Requirements'' (66 FR 23086, May 7, 2001). In addition to new airworthiness standards for transport airplanes and new maintenance requirements, this rule included Special Federal Aviation Regulation No. 88 (''SFAR 88,'' Amendment 21–78, and subsequent Amendments 21–82 and 21–83).

Among other actions, SFAR 88 requires certain type design (i.e., type certificate (TC) and supplemental type certificate (STC)) holders to substantiate that their fuel tank systems can prevent ignition sources in the fuel tanks. This requirement applies to type design holders for large turbine-powered transport airplanes and for subsequent modifications to those airplanes. It requires them to perform design reviews and to develop design changes and maintenance procedures if their designs do not meet the new fuel tank safety standards. As explained in the preamble to the rule, we intended to adopt airworthiness directives to mandate any changes found necessary to address unsafe conditions identified as a result of these reviews.

In evaluating these design reviews, we have established four criteria intended to define the unsafe conditions associated with fuel tank systems that require corrective actions. The percentage of operating time during which fuel tanks are exposed to flammable conditions is one of these criteria. The other three criteria address

the failure types under evaluation: Single failures, single failures in combination with a latent condition(s), and in-service failure experience. For all four criteria, the evaluations included consideration of previous actions taken that may mitigate the need for further action.

We have determined that the actions identified in this proposed AD are necessary to reduce the potential of ignition sources inside fuel tanks, which, in combination with flammable fuel vapors, could result in fuel tank explosions and consequent loss of the airplane.

We have received a report of an overheated and damaged sump heater on a center wing fuel tank. Investigation revealed that several incidents of this kind had occurred in the past and that damage was caused by fatigue failure of the sump heater thermostat. Additionally, SFAR 88 analysis has identified certain lightning protection issues with the center wing crossfeed and scavenge valves, as well as frictional heating and sparking issues with the scavenge pump. Deactivating the sump heater, the scavenge valve and the scavenge pump will address all three issues. If not corrected, operation with a damaged sump heater thermostat or scavenge pump, or operation of the crossfeed and scavenge valves during lightning conditions could lead to a possible ignition source in the fuel tank and a potential fire or explosion.

Relevant Service Information

We have reviewed Boeing Alert Service Bulletin DC8–28A089, dated November 1, 2006. The service bulletin describes procedures for deactivating the sump heater, scavenge valve, and scavenge pump of the center wing fuel tank. Accomplishing the actions specified in the service information is intended to adequately address the unsafe condition.

FAA's Determination and Requirements of the Proposed AD

We have evaluated all pertinent information and identified an unsafe condition that is likely to exist or develop on other airplanes of this same type design. For this reason, we are proposing this AD, which would require accomplishing the actions specified in the service information described previously.

Costs of Compliance

There are about 119 airplanes of the affected design in the worldwide fleet. The following table provides the estimated costs for U.S. operators to comply with this proposed AD.

ESTIMATED COSTS

Work hours	Average labor rate per hour	Cost per airplane	Number of U.S.-registered airplanes	Fleet cost
6	$80	$480	84	$40,320

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.

We are 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

We have determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would 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 the proposed regulation:

1. Is not a ''significant regulatory action'' under Executive Order 12866;

2. Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); 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.

We prepared a regulatory evaluation of the estimated costs to comply with this proposed AD and placed it in the AD docket. See the **ADDRESSES** section for a location to examine the regulatory evaluation.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 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 Federal Aviation Administration (FAA) amends § 39.13 by adding the following new airworthiness directive (AD):

McDonnell Douglas: Docket No. FAA–2007–27756; Directorate Identifier 2006–NM–255–AD.

Comments Due Date

(a) The FAA must receive comments on this AD action by May 21, 2007.

Affected ADs

(b) None.

Applicability

(c) This AD applies to all McDonnell Douglas Model DC–8–62, DC–8–62F, DC–8–63, DC–8–63F, DC–8–72, DC–8–72F, and DC–8–73F airplanes, certificated in any category.

Unsafe Condition

(d) This AD results from fuel system reviews conducted by the manufacturer. We are issuing this AD to prevent certain conditions related to the sump heater, scavenge valve, and scavenge pump of the center wing fuel tank, which could lead to a possible ignition source in the fuel tank and a potential fire or explosion.

Compliance

(e) You are responsible for having the actions required by this AD performed within the compliance times specified, unless the actions have already been done.

Deactivation

(f) Within 24 months after the effective date of this AD, deactivate the sump heater,

scavenge valve, and scavenge pump of the center wing fuel tank, in accordance with the Accomplishment Instructions of Boeing Alert Service Bulletin DC8–28A089, dated November 1, 2006.

Alternative Methods of Compliance (AMOCs)

(g)(1) The Manager, Los Angeles Aircraft Certification Office, FAA, has the authority to approve AMOCs for this AD, if requested in accordance with the procedures found in 14 CFR 39.19.

(2) Before using any AMOC approved in accordance with § 39.19 on any airplane to which the AMOC applies, notify the appropriate principal inspector in the FAA Flight Standards Certificate Holding District Office.

Issued in Renton, Washington, on March 26, 2007.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–6269 Filed 4–3–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2007–27755; Directorate Identifier 2006–NM–289–AD]

RIN 2120–AA64

Airworthiness Directives; Bombardier Model DHC–8–400 Series Airplanes

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to adopt a new airworthiness directive (AD) for certain Bombardier Model DHC–8–400 series airplanes. This proposed AD would require revising the Limitations section of the airplane flight manual to include procedures for pulling the ''HYD PWR XFER'' circuit breaker in the event of the loss of all hydraulic fluid in the No. 1 or No. 2 hydraulic system. This proposed AD results from reports of fluid loss in the No. 2 hydraulic system, causing the power transfer unit to overspeed, increasing the fluid flow within the No. 1 hydraulic system. We are proposing this AD to prevent possible loss of both the No. 1 and No. 2 hydraulic systems, resulting in the potential loss of several functions essential for safe flight and landing of the airplane.

DATES: We must receive comments on this proposed AD by May 4, 2007.

ADDRESSES: Use one of the following addresses to submit comments on this proposed AD.

- DOT Docket Web site: Go to *http://dms.dot.gov* and follow the instructions for sending your comments electronically.
- *Government-wide rulemaking Web site:* Go to *http://www.regulations.gov* and follow the instructions for sending your comments electronically.
- *Mail:* Docket Management Facility, U.S. Department of Transportation, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC 20590.
- *Fax:* (202) 493–2251.
- *Hand Delivery:* Room PL–401 on the plaza level of the Nassif Building, 400 Seventh Street, SW., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Contact Bombardier, Inc., Bombardier Regional Aircraft Division, 123 Garratt Boulevard, Downsview, Ontario M3K 1Y5, Canada, for service information identified in this proposed AD.

FOR FURTHER INFORMATION CONTACT: Ezra Sasson, Aerospace Engineer, Systems and Flight Test Branch, ANE–172, FAA, New York Aircraft Certification Office, 1600 Stewart Avenue, Suite 410, Westbury, New York 11590; telephone (516) 228–7320; fax (516) 794–5531.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to submit any relevant written data, views, or arguments regarding this proposed AD. Send your comments to an address listed in the **ADDRESSES** section. Include the docket number ''FAA–2007–27755; Directorate Identifier 2006–NM–289–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of the proposed AD. We will consider all comments received by the closing date and may amend the proposed AD in light of those comments.

We will post all comments we receive, without change, to *http://dms.dot.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact with FAA personnel concerning this proposed AD. Using the search function of that web site, anyone can find and read the comments in any of our dockets, including the name of the individual who sent the comment (or signed the comment on behalf of an association, business, labor union, etc.). You may review the DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477–78), or you may visit *http://dms.dot.gov.*

Examining the Docket

You may examine the AD docket on the Internet at *http://dms.dot.gov,* or in person at the Docket Management Facility office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Docket Management Facility office (telephone (800) 647–5227) is located on the plaza level of the Nassif Building at the DOT street address stated in the **ADDRESSES** section. Comments will be available in the AD docket shortly after the Docket Management System receives them.

Discussion

Transport Canada Civil Aviation (TCCA), which is the airworthiness authority for Canada, notified us that an unsafe condition may exist on certain Bombardier Model DHC–8–400 series airplanes. TCCA advises that it has received several reports of fluid loss in the No. 2 hydraulic system, causing the power transfer unit (PTU) to overspeed. This resulted in pressure fluctuations and increased fluid flow within the No. 1 hydraulic system. In one case, the hydraulic system control logic did not shut down the PTU, and the overspeed condition persisted, resulting in the illumination of the No. 1 ''HYD FLUID HOT'' caution light. This caution light indicated that the hydraulic fluid temperature had exceeded 225 degrees Fahrenheit. Had the temperature of the hydraulic fluid continued to increase to 275 degrees Fahrenheit, the No. 1 system hydraulic firewall shutoff would have closed, leaving only the standby power unit (SPU) available. The SPU is not capable of meeting the increased flow demands of the PTU and other No. 1 hydraulic system services. Therefore, the No. 1 hydraulic system would have also been lost, leaving only the No. 3 hydraulic system available. Inoperative systems would include flaps, brakes and emergency brakes, nose wheel steering, and all primary flight controls other than elevator control and degraded aileron control.

This condition, if not corrected, could result in the potential loss of several functions essential for safe flight and landing of the airplane.

Relevant Service Information

Bombardier has issued the following airplane flight manual (AFM) temporary amendments:

TABLE.—AFM TEMPORARY AMENDMENTS

For model—	Bombardier temporary amendment—	Issue—	Dated—	To Bombardier Dash 8 Q400 airplane flight manual—
–400 airplanes	13	1	July 14, 2005	PSM 1–84–1A
–401 airplanes	13	1	July 14, 2005	PSM 1–84–1A
–402 airplanes	13	1	July 14, 2005	PSM 1–84–1A

The temporary amendments describe procedures for pulling the ''HYD PWR XFER'' circuit breaker in the event of the loss of all hydraulic fluid in the No. 1 or No. 2 hydraulic system. TCCA mandated the service information and issued Canadian airworthiness directive CF–2006–08, dated April 26, 2006, to ensure the continued airworthiness of these airplanes in Canada.

FAA's Determination and Requirements of the Proposed AD

These airplanes are manufactured in Canada and are type certificated for operation in the United States under the provisions of section 21.29 of the Federal Aviation Regulations (14 CFR 21.29) and the applicable bilateral airworthiness agreement. Pursuant to this bilateral airworthiness agreement, TCCA has kept the FAA informed of the situation described above. We have examined TCCA's findings, evaluated all pertinent information, and determined that we need to issue an AD for airplanes of this type design that are certificated for operation in the United States. Therefore, we are proposing this AD, which would require revising the Limitations section of the AFM to include procedures for pulling the ''HYD PWR XFER'' circuit breaker in the event of the loss of all hydraulic fluid in the No. 1 or No. 2 hydraulic system.

Interim Action

We consider this proposed AD interim action. The manufacturer is currently developing a modification that will address the unsafe condition identified in this proposed AD. Once this modification is developed, approved, and available, we might consider additional rulemaking.

Costs of Compliance

The following table provides the estimated costs for U.S. operators to comply with this proposed AD.

ESTIMATED COSTS

Action	Work hours	Average labor rate per hour	Parts	Cost per airplane	Number of U.S.-registered airplanes	Fleet cost
AFM revision	1	$80	$0	$80	21	$1,680

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.

We are 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

We have determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would 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 the proposed regulation:

1. Is not a ''significant regulatory action'' under Executive Order 12866;

2. Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); 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.

We prepared a regulatory evaluation of the estimated costs to comply with this proposed AD and placed it in the AD docket. See the **ADDRESSES** section for a location to examine the regulatory evaluation.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 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 Federal Aviation Administration (FAA) amends § 39.13 by adding the following new airworthiness directive (AD):

Bombardier, Inc. (Formerly de Havilland, Inc.): Docket No. FAA–2007–27755; Directorate Identifier 2006–NM–289–AD.

Comments Due Date

(a) The FAA must receive comments on this AD action by May 4, 2007.

Affected ADs

(b) None.

Applicability

(c) This AD applies to Bombardier Model DHC–8–400, DHC–8–401, and DHC–8–402

airplanes, certificated in any category; serial numbers 4001 and 4003 and subsequent.

Unsafe Condition

(d) This AD results from reports of fluid loss in the No. 2 hydraulic system, causing the power transfer unit to overspeed, increasing the fluid flow within the No. 1 hydraulic system. We are issuing this AD to prevent possible loss of both the No. 1 and No. 2 hydraulic systems, resulting in the potential loss of several functions essential for safe flight and landing of the airplane.

Compliance

(e) You are responsible for having the actions required by this AD performed within the compliance times specified, unless the actions have already been done.

Airplane Flight Manual (AFM) Revision

(f) Within 14 days after the effective date of this AD, revise the Limitations section of the applicable AFM to include the information in the applicable Bombardier temporary amendment specified in Table 1 of this AD, as specified in the temporary amendment. These temporary amendments introduce procedures for pulling the ''HYD PWR XFER'' circuit breaker in the event of the loss of all hydraulic fluid in the No. 1 or No. 2 hydraulic system. Operate the airplane according to the limitations and procedures in the applicable temporary amendment.

TABLE 1.—AFM TEMPORARY AMENDMENTS

For Model—	Use Bombardier Temporary Amendment—	Issue—	Dated—	To Bombardier Dash 8 Q400 Airplane Flight Manual—
–400 airplanes	13	1	July 14, 2005	PSM 1–84–1A.
–401 airplanes	13	1	July 14, 2005	PSM 1–84–1A.
–402 airplanes	13	1	July 14, 2005	PSM 1–84–1A.

Note 1: This may be done by inserting a copy of the applicable temporary amendment into the applicable AFM. When the applicable temporary amendment has been included in general revisions of the AFM, the general revisions may be inserted into the AFM, provided the relevant information in the general revisions is identical to that in the temporary amendment.

Alternative Methods of Compliance (AMOCs)

(g)(1) The Manager, New York Aircraft Certification Office, FAA, has the authority to approve AMOCs for this AD, if requested in accordance with the procedures found in 14 CFR 39.19.

(2) Before using any AMOC approved in accordance with § 39.19 on any airplane to which the AMOC applies, notify the appropriate principal inspector in the FAA Flight Standards Certificate Holding District Office.

Related Information

(h) Canadian airworthiness directive CF–2006–08, dated April 26, 2006, also addresses the subject of this AD.

Issued in Renton, Washington, on March 26, 2007.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. E7–6267 Filed 4–3–07; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 179

[Docket No. 2005N–0272]

RIN 0910–ZA29

Irradiation in the Production, Processing and Handling of Food

AGENCY: Food and Drug Administration, HHS.

ACTION: Proposed rule.

SUMMARY: The Food and Drug Administration (FDA) is proposing to revise its labeling regulations applicable to foods (including dietary supplements) for which irradiation has been approved by FDA. FDA is proposing that only those irradiated foods in which the irradiation causes a material change in the food, or a material change in the consequences that may result from the use of the food, bear the radura logo and the term ''irradiated,'' or a derivative thereof, in conjunction with explicit language describing the change in the food or its conditions of use. For purposes of this rulemaking, we are using the term ''material change'' to refer to a change in the organoleptic, nutritional, or functional properties of a food, caused by irradiation, that the consumer could not identify at the point of purchase in the absence of appropriate labeling. FDA is also proposing to allow a firm to petition FDA for use of an alternate term to ''irradiation'' (other than ''pasteurized''). In addition, FDA is proposing to permit a firm to use the term ''pasteurized'' in lieu of ''irradiated,'' provided it notifies the agency that the irradiation process being used meets the criteria specified for use of the term ''pasteurized'' in the Federal Food, Drug, and Cosmetic Act (the act) and the agency does not object to the notification. This proposed action is in response to the Farm Security and Rural Investment Act of 2002 (FSRIA) and, if finalized, will provide consumers with more useful information than the current regulation.

DATES: Submit written or electronic comments on the proposed rule by July 3, 2007. Submit comments regarding information collection by May 4, 2007 to OMB (see **ADDRESSES**).

ADDRESSES: You may submit comments, identified by Docket No. 2005N–0272 by any of the following methods:

Electronic Submissions

Submit electronic comments in the following ways:

- Federal eRulemaking Portal: *http://www.regulations.gov*. Follow the instructions for submitting comments.
- Agency Web site: *http://www.fda.gov/dockets/ecomments*. Follow the instructions for submitting comments on the agency Web site.

Written Submissions

Submit written submissions in the following ways:

- FAX: 301–827–6870.
- Mail/Hand delivery/Courier [For paper, disk, or CD–ROM submissions]: Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, rm. 1061, Rockville, MD 20852.

To ensure more timely processing of comments, FDA is no longer accepting comments submitted to the agency by e-mail. FDA encourages you to continue to submit electronic comments by using the Federal eRulemaking Portal or the agency Web site, as described in the

Electronic Submissions portion of this paragraph.

Instructions: All submissions received must include the agency name and Docket No. 2005N–0272 or Regulatory Information Number (RIN) for this rulemaking. All comments received will be posted without change to *http://www.fda.gov/ohrms/dockets/default.htm*, including any personal information provided. For detailed instructions on submitting comments and additional information on the rulemaking process, see the ''Comments'' heading of the **SUPPLEMENTARY INFORMATION** section of this document.

Docket: For access to the docket to read background documents or comments received, go to *http://www.fda.gov/ohrms/dockets/default.htm* and insert the docket number, found in brackets in the heading of this document, into the ''Search'' box and follow the prompts and/or go to the Division of Dockets Management, 5630 Fishers Lane, rm. 1061, Rockville, MD 20852.

Information Collection Provisions: Submit written comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB).To ensure that comments on the information collection are received, OMB recommends that written comments be faxed to the Office of Information and Regulatory Affairs, OMB, Attn: FDA Desk Officer, FAX: 202–395–6974.

FOR FURTHER INFORMATION CONTACT: Loretta A. Carey, Center for Food Safety and Applied Nutrition (HFS–820), Food and Drug Administration, 5100 Paint Branch Pkwy., College Park, MD 20740, 301–436–2371.

SUPPLEMENTARY INFORMATION:

I. Background

A. Current Labeling Requirements for Irradiated Foods

In the **Federal Register** of February 14, 1984 (49 FR 5714), FDA published a proposed rule (the 1984 proposal) to approve the use of ionizing radiation on several foods. The 1984 proposal did not include a requirement for labeling disclosing the use of ionizing radiation. FDA received over 5,000 comments on this proposal, including numerous comments on the issue of labeling irradiated foods. Based on the comments and information received in response to the 1984 proposal and on further analysis, FDA published a final rule in the **Federal Register** on April 18, 1986 (51 FR 13376) (the 1986 final rule). The 1986 final rule required that the label and labeling of retail packages and displays of irradiated food bear both the radura logo and a radiation disclosure statement (''Treated with radiation'' or ''Treated by irradiation''). FDA concluded that labeling indicating treatment of food with radiation was necessary to prevent misbranding of irradiated foods because irradiation may not visually change the food and in the absence of a label statement, the implied representation to consumers is that the food has not been processed. We stated in the preamble to the 1986 final rule that, in addition to the mandatory language, the manufacturer may also state on the wholesale or retail label the purpose of the treatment process or further describe the kind of treatment used (51 FR 13376 at 13387). That is, the manufacturer may include in the labeling any phrase such as ''treated with radiation to control spoilage,'' ''treated with radiation to extend shelf life,'' or ''treated with radiation to inhibit maturation,'' as long as the phrase truthfully describes the primary purpose of the treatment. Similarly, the manufacturer may choose to state more specifically the type of radiation used in the treatment, i.e., ''treated with x-radiation,'' ''treated with ionizing radiation,'' or ''treated with gamma radiation,'' if more specific description is applicable.

B. The 1999 Advanced Notice of Proposed Rulemaking (ANPRM) on the Labeling of Irradiated Foods

On November 21, 1997, the Food and Drug Administration Modernization Act (FDAMA) (Public Law 105–115) was enacted. Section 306 of FDAMA amended the act by adding section 403C (21 U.S.C. 343–3). Section 403C of the act addressed the disclosure of irradiation on the labeling of foods as follows:

''(a) No provision of section 201(n), 403(a), or 409 shall be construed to require on the label or labeling of a food a separate radiation disclosure statement that is more prominent than the declaration of ingredients required by section 403(i)(2).

(b) In this section, the term ''radiation disclosure statement'' means a written statement that discloses that a food has been intentionally subject to radiation.''

Although section 403C of the act addressed only the prominence of the radiation disclosure statements, the language in the FDAMA Joint Statement (H. Rep. 105–399, 105th Cong., 1st sess., at 98–99) stated that FDA should seek public comment on whether additional changes should be made to current regulations relating to the labeling of foods treated with ionizing radiation. Specifically, the Joint Statement stated that ''the public comment process should be utilized by the Secretary to provide an opportunity to comment on whether the regulations should be amended to revise the prescribed nomenclature for the labeling of irradiated foods and on whether such labeling requirements should expire at a specified date in the future.'' The FDAMA Joint Statement also indicated that ''The conferees intend for any required irradiation disclosure to be of a type and character such that it would not be perceived to be a warning or give rise to inappropriate anxiety'' (Ref. 1).

In response to the conferees' report, FDA published an ANPRM in the **Federal Register** of February 17, 1999 (64 FR 7834) seeking public comment on the meaning of the current irradiation labeling statement and soliciting suggestions for possible revisions. The 1999 ANPRM described the intent of the conference report, cited several documents related to irradiation labeling, and asked for comment on how the current label is perceived by consumers. The 1999 ANPRM also described whether other labeling would more accurately convey that the food was irradiated without implying a warning or causing inappropriate consumer anxiety.

FDA received over 5,550 comments in response to the 1999 ANPRM on the meaning of the current irradiation labeling statement and suggestions for possible revisions. The majority of comments urged FDA to retain the current labeling for irradiated foods. Some comments suggested alternate wording, such as ''cold pasteurization,'' or ''electronic pasteurization,'' while other comments contended that these terms serve only to obscure information and confuse consumers. A few comments stated that additional labeling, such as ''irradiated to kill harmful bacteria,'' was helpful.

C. Consumer Research

To better assist FDA in formulating specific revisions that would accomplish the objectives outlined in the FDAMA Joint Statement and also satisfy the requirements of the act, the agency, in addition to publishing the ANPRM, conducted focus group research in Maryland, Minnesota, and California, during June and July 2001. The primary focus of the research was to ascertain from focus group participants how they viewed the current irradiation disclosure statement. We were particularly interested in whether the focus group participants perceived the current irradiation disclosure statement as a warning. The

focus group data indicated that the majority of participants were uncertain about the safety, effectiveness, and appropriateness of irradiated food products and greatly desired more information. Most of the participants viewed alternate terms, such as ''cold pasteurization'' and ''electronic pasteurization,'' as misleading, because such terms appeared to conceal rather than to disclose information. Participants did not see the current disclosure labeling as a warning, per se, because knowledgeable participants considered irradiation to be a positive safety attribute. Less knowledgeable participants, such as those who associated irradiation with things such as x-ray or radiation, wanted more information about the appropriateness of food irradiation. All participants agreed that irradiated foods should be labeled ''honestly.''

D. Farm Security and Rural Investment Act of 2002 (FSRIA) (Public Law 107–171)

On May 13, 2002, the President signed into law the FSRIA. The law included two provisions that relate to irradiation labeling. One of these provisions, section 10808, as discussed in the following paragraph, includes new criteria for use of the term ''pasteurization'' in labeling. The other provision, section 10809, directed FDA to publish for public comment proposed changes to the current regulations relating to the labeling of foods that have been treated by irradiation using radioactive isotope, electronic beam, or x-ray to reduce pest infestation or pathogens. The provision further stated that ''[p]ending promulgation of the final rule * * * any person may petition the Secretary [FDA] for approval of labeling, which is not false or misleading in any material respect, of a food which has been treated by irradiation using radioactive isotope, electronic beam, or x-ray.'' Section 10809 also requires that, pending issuance of the final rule, ''* * * [t]he Secretary [FDA] shall approve or deny such a petition within 180 days of receipt of the petition, or the petition shall be deemed denied, except to the extent additional agency review is mutually agreed upon by the Secretary [FDA] and the petitioner.''

Section 10808 of the FSRIA, which includes new criteria for use of the term ''pasteurized'' in labeling, revised section 403(h) of the act to provide that a food may purport to be or be represented as pasteurized if the food has been subjected to a safe process or treatment that is prescribed as pasteurization for such food in a regulation issued under the act or the food has been subjected to a safe process or treatment that meet certain criteria. The criteria prescribed in section 10808 of the FSRIA are that the food has been subjected to a safe process that: (1) Is reasonably certain to achieve destruction or elimination in the food of the most resistant micro-organisms of public health significance that are likely to occur in the food, (2) is at least as protective of the public health as a process or treatment prescribed by regulation as pasteurization, (3) is effective for a period that is at least as long as the shelf life of the food when stored under normal and moderate abuse conditions, and (4) is the subject of a notification to the Secretary (FDA) that includes effectiveness data regarding the process or treatment and at least 120 days have passed after receipt of such notification without the Secretary making a determination that the process or treatment involved has not been shown to meet the requirements.

As part of FDA's implementation of section 10809 of the FSRIA, FDA issued a guidance document entitled ''Guidance; Implementation of Section 10809 of the Farm Security and Rural Investment Act of 2002, Public Law No. 107–171, section 10809 (2002) Regarding the Petition Process to Request Approval of Labeling for Foods That Have Been Treated by Irradiation'' (the 2002 Guidance). The 2002 Guidance was issued in accordance with FDA's Good Guidance Practices regulation in 21 CFR 10.115. The 2002 Guidance also advised how interested parties may petition the agency for the approval of labeling that may be used on irradiated food as an alternative to the currently required irradiation disclosure statement. FDA noted that this was an interim process and that it could be used until FDA published any final regulation on this issue. FDA published a notice in the **Federal Register** announcing the availability of the 2002 Guidance document on October 7, 2002 (67 FR 62487). To date, FDA has not received any petitions requesting the use of alternative labeling for irradiated foods.

II. The Proposal

A. Legal Authority/Statutory Directive

FDA's authority to require labeling of all foods[1], including irradiated foods, derives from sections 201(n) and 403(a)(1) of the act (21 U.S.C. 321(n) and 343(a)(1)). In addition, section 701(a) of the act (21 U.S.C. 371(a)) authorizes FDA to issue regulations for the efficient enforcement of the act. Under section 403(a)(1) of the act, a food is misbranded if ''its labeling is false or misleading in any particular.'' Section 201(n) of the act mandates that, in determining whether labeling is misleading, FDA take into account, among other things, whether the labeling fails to reveal facts that are material in the light of representations made or suggested or with respect to consequences that may result from the use of the product to which the labeling relates under the conditions of use prescribed in the labeling or under such conditions of use as are customary or usual.

Historically, the agency has generally interpreted the scope of the materiality concept to mean information about the characteristics of the food. FDA has required special labeling on the basis of it being ''material'' information in cases where the absence of such information leads the consumer to assume that a food, because of its similarity to another food, has nutritional[2], organoleptic (e.g., taste, smell, or texture), or functional (e.g., storage)[3] properties of the food it resembles when in fact it does not. For example, the labeling of margarine that has been processed in a way that results in it no longer being suitable for frying must disclose this difference from regular margarine.

Irradiation has various effects on foods that may cause changes in the characteristics of the food. Such changes may occur in the food's organoleptic, nutritional, or functional properties that would not be noticeable at the point of purchase but could be apparent when consumed or cooked. If these changes are not within the range of characteristics ordinarily found in such foods, they would be considered ''material'' under this proposal. In the absence of appropriate labeling disclosing these changes in the characteristics of the food, consumers would not have all of the necessary information needed to make a purchase decision or properly use the food. Thus, in the absence of information about these changes in the characteristics of the food, the labeling would be misleading under 201(n) of the act and the food would be misbranded. These

[1] Food refers to conventional foods as well as dietary supplements.

[2] Currently, we are not aware of any changes to the nutritional properties of any food FDA has approved for irradiation.

[3] The statutory phrase ''the consequences that may result from the use of the food'' (section 201(n) of the act) generally can also be described as changes in a food's functional properties. For brevity and clarity, we use the latter terminology in this document.

changes are typically process specific and will vary with the food and the irradiation conditions. In addition, these changes and the degree of the changes may be measurable and of consequence to consumers. Thus, a blanket statement on when labeling would be required due to irradiation causing material changes cannot be made in advance for all products. Rather, the need for labeling must be determined on a case-by-case basis by appropriate testing of the food irradiated under specific conditions, e.g., time and dosage, because the effect of irradiation on the properties of concern depends on the particular food.

Under the proposal, the fact that a food has been irradiated would not by itself require disclosure on the label. FDA is proposing to require that only those irradiated foods in which irradiation causes a material change in a food's characteristics (e.g., organoleptic, nutritional, or functional properties) under the conditions of use prescribed in the label and labeling or under customary or usual conditions of use bear the radura logo. Those irradiated foods must also bear the term ''irradiated'' or any derivative thereof (e.g., ''irradiate,'' ''irradiation,'' ''radiation,'' etc.) in conjunction with language describing the material change. Additionally, FDA will not object to the use of additional terms to indicate that a food has been subjected to the process of irradiation, e.g., ''treated with radiation,'' ''treated by irradiation,'' or ''processed with radiation.'' However, in the absence of a material change, under the proposal, the fact that the food has been irradiated is not considered a material fact and, therefore, no logo or label statement would be needed. For such foods, FDA would not object to manufacturers voluntarily labeling their products to indicate that the food is irradiated. FDA is also proposing to allow the use of alternate terms to ''irradiated'' or any of its derivatives if use of the term has been approved by FDA in response to a citizen petition submitted in accordance with § 10.30 (21 CFR 10.30).

As discussed in more detail in section I of this document, the FSRIA amended section 403(h) of the act to include new criteria for the use of the term ''pasteurized'' in labeling. This section gives FDA authority to determine for labeling purposes whether alternate processes, e.g., irradiation, are equivalent to pasteurization in destroying pathogens. Therefore, FDA is also proposing to require that anyone seeking to label a food as ''pasteurized'' under this provision in lieu of referring to irradiation must notify FDA and provide supportive data. Provided the agency has not objected to the notification within 120 days after receipt of the notification, the notifier would be able to label a food as ''pasteurized'' in lieu of ''irradiated.''

Under section 409 of the act, no food may be irradiated without approval by FDA. Currently, FDA has approved irradiation for a number of foods, including spices, shell eggs and fruits and vegetables, although only a small fraction of these foods are actually irradiated. According to a report by the U.S. General Accounting Office[4] (2000), only 0.005 percent of fruits and vegetables consumed in the United States (about 1.5 million pounds), and 9.5 percent of all spices consumed in the United States (about 95 million pounds of spices and dry or dehydrated aromatic vegetable substances) are irradiated annually. See the following Web site for a listing of all foods that have been approved for irradiation: *http://a257.g.akamaitech.net/7/257/2422/10apr20061500/edocket.access.gpo.gov/cfr_2006/aprqtr/21cfr179.26.htm*.

B. Proposed Amendment

As previously discussed in section II.A of this document, irradiation has various effects on foods that may change a food's characteristics. For example, as with other forms of processing, the effects of irradiation that kill or weaken insects and microorganisms may also cause some changes in the food itself. Many of these changes are of little significance, as the composition of the food will remain within normal variations of unirradiated foods. However, other changes to organoleptic, nutritional, and functional properties may occur. Changes to shelf life are likely to be among the most common of these changes. Bananas and spices are illustrative of irradiated foods that may have an extended shelf life and are discussed in the following paragraph.

Bananas may be irradiated to delay ripening and extend shelf life. This is an example of a material change. Consumers have a general idea of the shelf life and ripening time of unirradiated bananas based upon their appearance and make purchase decisions based at least in part on the bananas' appearance (i.e., ripeness) and intended use. If irradiated bananas were not labeled to indicate the material change, e.g., delayed ripening, consumers would purchase the bananas expecting the faster ripening schedule of unirradiated bananas. A consumer who wanted to make a food that required very ripe bananas (e.g., banana bread) would not know, without labeling, that the irradiated bananas would not be ripe enough to make the banana bread when he wanted to do so. Thus, if the irradiated bananas are not labeled, the consumer might purchase the bananas and then discover later that they are unsuitable for the consumer's planned use.

In contrast, there are instances where treatment with irradiation may extend a food's shelf life without changing any of its functional characteristics in a way that may require using the food differently than its unirradiated counterpart. For example, while spices that are irradiated to control microbial growth will likely have their shelf life extended, FDA tentatively believes that the extension in shelf life in this case does not have the potential to be detrimental to the consumer (e.g., to prevent the consumer's planned use of the food) because the irradiated spice can be used identically to an unirradiated spice. That is, in addition to possibly benefiting from the extended shelf life, a consumer buying the irradiated spice can use the irradiated spice the same as he would the unirradiated spice. Unlike the consumer of irradiated bananas described above, the spice consumer does not need additional information to prevent the potential for a detrimental consequence from using the irradiated food the same as its unirradiated counterpart. Thus, FDA tentatively believes that the extension of a spice's shelf life due to irradiation would not be material information that consumers need to know; therefore the producer would not be required to declare this information on the spice label. We request comment on the utility, for purposes of labeling, of distinguishing between those changes to a food's functional properties from irradiation that may make a food unsuitable for a particular use (e.g., delayed ripening) and those changes that still allow for the food to be used identically to one that is not irradiated (e.g., extension of shelf life alone).

One of the goals of food science research on irradiation is to determine irradiation conditions that would minimize those unexpected effects that would be material to consumers. In a review article on the effects of irradiation on fresh-cut fruits and vegetables, Prakash and Foley (Ref. 1a) cite research illustrating how effects can vary depending on the food, irradiation conditions, and mitigating steps that can be taken. They report that in some cases low doses can cause significant loss in firmness; however, in other fruits and vegetables no such loss is observed, even at a higher dose. For example,

[4] Now the Government Accountability Office.

firmness of diced Roma tomatoes irradiated at 0.5 kilogray (kGy) decreased by 30 percent and firmness of cut romaine lettuce irradiated at 0.35 kGy decreased by 10 percent. However, no change in firmness was observed in shredded carrots or fresh-cut iceberg lettuce following irradiation at 1 and 2 kGy, or in celery irradiated at 1 kGy. In diced bell peppers, irradiation at 3.7 kGy reduced bell peppers' flavor and produced some off-flavors, while no effect on flavor or aroma was perceived in a control group of bell peppers that were not irradiated and in peppers irradiated at 1.32 kGy. Additionally, after storage for 9 days, off aroma was significantly higher in the control sample of bell peppers than in the two groups of irradiated peppers, coinciding with a slimy appearance attributed to microbial spoilage. Prakash and Foley also report that combining irradiation with other technologies, such as calcium treatment, warm water dips, and modified atmosphere packaging further mitigated measurable adverse effects on quality. Similarly, Kader (Ref. 1b) reported that fruits and vegetables such as papaya, strawberry, tomatoes, and dates have a high tolerance to irradiation at doses (below 1 kGy) used for insect control, while cucumber, green bean, grape, and lemon have a low tolerance at this same kilogray. Thus, whether effects occur that would change the food in a significant way will depend on the particular food that is irradiated and the dosage of irradiation used. In its decision approving the use of radiation on shell eggs, FDA cited to data in the petition showing an increased color loss in the irradiated egg yolk and a change in the egg's viscosity as the radiation dose was increased (65 FR 45280 at 45281; July 21, 2000). Such a change in the viscosity or other characteristics of the egg would affect its functionality, e.g., its cooking or binding properties. This change could be significant enough that consumers should be informed of the irradiation and its effect on the food.

In sum, irradiation of food can cause effects in food that are material in light of representations made or on consequences of use. However, whether such effects are sufficient to meet the standard of section 201(n) of the act will vary based on several factors and cannot be determined without considering the particular food and irradiation processing applied. If the change in the irradiated food is within the range of characteristics ordinarily found in such foods, then the fact that the food is irradiated and the resulting change would not be material information and would not be required to be declared on the label.

The use of irradiation is strictly voluntary and generally approved up to a maximum dose. We believe that manufacturers may adjust the dosage to get the most effective dose, while minimizing unexpected effects in the irradiated food. These food manufacturers or producers may choose to irradiate their food only if the irradiation does not alter in a significant way characteristics of the food that are material to the consumer. Thus, it is possible that many uses of irradiation will not result in a material change within the framework set out in this rule. FDA is interested in receiving information about the types of pre-market investigations, e.g., taste test panels or functional studies, done by food manufacturers to evaluate whether to irradiate and at what dose to irradiate in such a way that a material change does not result.

Food is most commonly irradiated to control food-borne pathogens. FDA is not aware of data indicating that control of food-borne pathogens as a result of food irradiation would, by itself, result in a change in the food's characteristics that would not be apparent at the point of purchase of the food and, thus, would have to be disclosed in the labeling of the food to prevent the labeling from being misleading. Consumers expect food to be safe and of a certain quality, and therefore, FDA tentatively concludes that control of food-borne pathogens alone is not an unexpected change in the food. Thus, in instances where a food has been irradiated to enhance or maintain the safety of a food by controlling food-borne pathogens that may be present, and no other changes to the food have resulted, FDA tentatively concludes that information that the food has been irradiated is not necessary to prevent the labeling from being misleading. FDA is interested in receiving any information on whether the control of food-borne pathogens changes the characteristics of the food in an unexpected way, i.e., outside of the normal variation of the food, and would therefore require additional labeling to inform the consumer of such change. FDA also solicits comments on any specific changes that might be caused by irradiation that might constitute non-material changes.

On the other hand, there may be situations in which irradiation to control food-borne pathogens has had other effects on foods, such as changes to organoleptic, nutritional, or functional properties which would not be readily apparent to the consumer. In such situations, information that there are changes in the characteristics of the food as a consequence of irradiation is the material information that is required in labeling in keeping with the act, to prevent the labeling from being misleading. Further, with regard specifically to shelf life, FDA recognizes that irradiation to control the growth of food-borne pathogens may have the unintended effect of extending shelf life. We specifically request comment on the effect of irradiation on shelf life and the extent of any relationship between control of food-borne pathogens and extension of shelf life.

In the past, FDA policies on irradiation labeling have focused on the fact that the food has been processed. In the preamble to the 1986 final rule, we stated that ''* * * irradiation may not change the food visually so that in the absence of a statement that a food has been irradiated, the implied representation to consumers is that the food has not been processed'' (51 FR 13376 at 13388). FDA concluded that, to prevent deception, the fact that the irradiated food is processed is material information that is required to be disclosed on the label. Thus, FDA required in § 179.26(c) (21 CFR 179.26(c)) that, in addition to the radura logo, the label and labeling of irradiated foods bear the statement ''Treated with radiation'' or ''Treated by irradiation.''

In recent years, FDA policies on the labeling of foods have focused on the results of the processing of the food rather than the processing itself. As discussed earlier, although foods that have been irradiated have been processed, the irradiation does not always result in a material change in the food or in the consequences of use. Further, FDA consumer research indicates that information provided to consumers on the labels of foods is more meaningful if it describes the purpose of the irradiation (Ref. 2). FDA recognizes that labeling to inform the consumer that the product has been irradiated does not, in itself, inform the consumer if or how the product is materially changed. Thus, FDA tentatively believes that when the irradiation causes a material change in the characteristics of the food, the consumer needs to know about this change, and not just the fact that the food has been irradiated. FDA believes that this information should be provided in a disclosure statement on the label of the irradiated food. The disclosure statement would describe the material change in the properties of the food and give consumers additional information that would enable them to make better informed decisions about whether to purchase an irradiated food.

Therefore, FDA is proposing to amend § 179.26(c)(1) and (c)(2) to require that only those foods that have been treated with radiation, and in which the irradiation caused a material change in the characteristics of the food must bear the radura logo and the term ''irradiated,'' or other derivatives as discussed previously in section II.A in conjunction with explicit language describing the change in the food or its conditions of use (e.g., ''irradiated to inhibit sprouting''). In addition, as noted in the 1986 final rule (51 FR 13376 at 13391), FDA believes that the logo is still a necessary part of the label statement because it derives from the symbol that has been used internationally to convey the fact that the food has been irradiated. FDA tentatively concludes that this approach is appropriate because it would require that consumers be provided with more precise information about the material change in the characteristics of the food than what is currently required. As noted previously, such material changes may affect how products are stored and subsequently used by consumers, as well as whether or not the products are purchased in the first place. However, FDA requests comments on whether the term that describes the process, e.g., ''irradiated'' or an alternate term such as ''pasteurized,'' is a necessary part of the label statement to ensure that consumers completely understand the statement.

As previously discussed in section I.D of this document, section 10809 of the FSRIA provides that anyone requesting approval of alternative labeling for a food that has been treated by irradiation, may petition FDA. As discussed in the 2002 Guidance, FDA believes that it is appropriate to use the citizen petition process provided in § 10.30. This regulation requires the petitioner to submit to the agency all relevant information regarding the petition. This relevant information includes both the information and views upon which the petitioner relies and the information known to the petitioner that is unfavorable to the petitioner's position. Thus for these purposes, relevant information would include any data known or relied upon by the petitioner (e.g., qualitative or quantitative consumer research), that show consumer understanding of the purpose and intent of the proposed alternative labeling. FDA believes that such information might include, but is not limited to, the following information: (1) Data on consumers' prior assumptions about, and perceptions of, the product characteristics in light of the proposed labeling statements and (2) data on consumer acceptance and comprehension of the proposed labeling statements in comparison to consumer acceptance and comprehension of the irradiation statement required by the current regulation (§ 179.26(c)(1)). Also, as noted in section I.D of this document, section 10808 of the FSRIA revised section 403(h) of the act to permit the use of the term ''pasteurized'' on labels of foods that have been subjected to a safe process as long as the process meets certain criteria.

Therefore, we are proposing in § 179.26(c)(1) to permit the use of alternate terms to ''irradiated'' or any of its derivatives, on the labels and labeling of irradiated foods. We are proposing in § 179.26(c)(2) that the alternate term may be used on the labels and labeling of foods that have been treated by irradiation, that is, if use of the term has been approved by FDA in response to a citizen petition submitted in accordance with § 10.30. In the case that the alternative term is ''pasteurized,'' the irradiation process must meet the criteria of section 403(h)(3) of the act. Anyone seeking to label a food as ''pasteurized'' under this provision must notify FDA and provide effectiveness data regarding the process or treatment used. The agency intends to issue guidance to interested parties who wish to notify the agency to use the term ''pasteurized'' in accordance with section 403(h)(3) of the act.

FDA and the Food Safety and Inspection Service (FSIS), U.S. Department of Agriculture, entered into a memorandum of understanding (MOU) establishing procedures to jointly respond to petitions to use food ingredients and sources of irradiation in the production of meat and poultry products (see 64 FR 72168, December 23, 1999, at *http://www.fsis.usda.gov/OPPDE/rdad/FRPubs/88-026F.pdf*; for the MOU, see *http://www.fsis.usda.gov/Regulations_&_Policies/Labeling_FDA_MOU/index.asp*). FSIS has separately issued regulations at 9 CFR 424.22(c) regarding the irradiation of meat and poultry products (see 64 FR 72150, December 23, 1999, at *http://www.fsis.usda.gov/OPPDE/rdad/FRPubs/97-076F.pdf*).

III. Analysis of Economic Impacts

A. Introduction

FDA has examined the economic implications of this proposed rule as required by Executive Order 12866, the Regulatory Flexibility Act (5 U.S.C. 601–612), and the Unfunded Mandates Reform Act of 1995 (Public Law 104–4). Executive Order 12866 directs agencies to assess all costs and benefits of available regulatory alternatives and, when regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity). Executive Order 12866 classifies a rule as significant if it meets any one of a number of specified conditions, including: having an annual effect on the economy of $100 million or more or adversely affecting in a material way a sector of the economy, competition, jobs, the environment, public health, or safety, or State, local, or tribal governments or communities. A regulation also is considered a significant regulatory action if it raises novel legal or policy issues. We have determined that this rule is a significant regulatory action as defined by Executive Order 12866 because it raises novel policy issues.

B. Preliminary Regulatory Impact Analysis

1. The Need for the Proposed Irradiation Labeling Rule

Executive Order 12866 states, ''Federal agencies should promulgate only such regulations as are required by law, are necessary to interpret the law, or are made necessary by compelling need, such as failures of private markets to protect or improve the health and safety of the public, the environment, or the well being of the American people.''

As previously discussed in section I.D of this document, on May 13, 2002, the President signed into law the FSRIA, which contains a provision relating to irradiation labeling. Section 10809 directs FDA to publish a proposed rule and, with due consideration to public comment, a final rule to revise the current regulation governing the labeling of foods that have been treated by irradiation. This rule is proposed not to address any market failure, but to respond to section 10809 of FSRIA and because we tentatively believe that it may no longer be necessary to require that all irradiated food be labeled as such.

2. Regulatory Options

We analyzed five options for the proposed irradiation regulation:

- No new regulatory action (current state of the world, baseline).
- Remove labeling requirements for irradiated foods.
- Maintain the current labeling requirement (that is, all food that is irradiated must be labeled), but also require statements of purpose (e.g., ''Irradiated to extend shelf life'').

• Maintain the current labeling requirement, but also allow alternate terms to irradiation (e.g., ''pasteurized'').

• The proposed regulation—Only those foods treated with irradiation and for which the irradiation caused a material change in the food must bear the radura logo and the term ''irradiated'' or an alternate term such as ''pasteurized'' in conjunction with explicit language describing the change in the food or its conditions of use (e.g., ''irradiated to inhibit sprouting''). A food undergoes a material change if irradiation changes the properties of the food in a way that is not readily apparent to the consumer at the point of purchase. Therefore, in the absence of a material change, the fact that the food was irradiated is not considered a material fact and, therefore, no radura logo or label statement would be needed.

Option 1: No New Regulatory Action (baseline).

Taking no new regulatory action on irradiation labeling is option 1 in our analysis. The FSRIA requires FDA to publish a proposed rule and, with due consideration to public comment, a final rule to revise the current irradiation labeling regulation. So this is not a viable option. We include it here because the Office of Management and Budget (OMB) cost-benefit analysis guidelines recommend discussing statutory requirements that affect the selection of regulatory approaches. These guidelines also recommend analyzing the opportunity cost of legal constraints that prevent the selection of the regulatory action that best satisfies the philosophy and principles of Executive Order 12866. This option will serve as the baseline against which other options will be measured for assessing costs and benefits, and we assume the baseline has zero costs and benefits.

The current regulation (§ 179.26) states that irradiated food must bear the radura logo and the phrase ''Treated with radiation'' or ''Treated by irradiation'' and does not explicitly address the inclusion of additional information that directs attention to shelf life or food safety. Currently, FDA has approved iradiation for a number of foods including spices, shell eggs, and fruits and vegetables; however, only limited amounts of irradiated foods are sold in the United States. According to a report by the General Accounting Office[5] (2000), it is estimated that 97 million pounds of food products are irradiated annually (including ''meat food products'' under the Federal Meat Inspection Act and ''poultry'' under the Poultry Products Inspection Act[6], which are regulated by the United States Department of Agriculture), which is only a small fraction of the total amount of food consumed. For example, about 1.5 million pounds of fruits and vegetables are irradiated annually. This represents only 0.005 percent of the total amount of fruits and vegetables consumed. About 95 million pounds of spices and dry or dehydrated aromatic vegetable substances are irradiated annually, which represents 9.5 percent of all spices consumed. Because spices, shell eggs, fruits and vegetables account for virtually all the food irradiation done in the United States, we use only data about those foods in our economic analysis.

Option 2: Propose to remove labeling requirements for irradiated foods

This option also may not be viable because it could violate section 403(a) of the act, which provides that the labeling of all foods, including irradiated foods, must be truthful and not misleading. In addition, section 201(n) of the act mandates that, in determining whether particular labeling is misleading, FDA consider whether the labeling fails to reveal material facts in light of representations made, or with respect to, the consequences that may result from the use of the product. Having no labeling requirements might violate these provisions. If this option were chosen, costs and benefits would be generated if many firms ceased labeling their irradiated products.

Costs: Since this option would not require labeling, search costs would increase for purchasers who do not want irradiated food. There will be an increase in search costs because these consumers would need to increase efforts to find information about irradiated foods other than on the labels or in the labeling, or obtain knowledge of producers who irradiate their food products. If firms decide to drop labeling, they would incur relabeling and label inventory costs but they would choose the least costly labeling option.

Benefits: This option could be beneficial to those firms currently labeling irradiated food by allowing them to reclaim label space on the label for private purposes, such as marketing messages or label art. Without a labeling requirement, it is possible that irradiation would become more attractive to firms because of this benefit. Any increases in the numbers of irradiated foods could, in turn, result in increased food safety or shelf life.

Option 3: Maintain the current labeling requirement (i.e., require that all irradiated food be labeled ''Treated with radiation'' or ''Treated by irradiation,'' along with the radura logo), but propose to also require statements of purpose (e.g., ''Treated with irradiation to inhibit sprouting,'' etc.).

The current regulation (§ 179.26(c)) states that irradiated food must bear the radura logo and the phrase ''Treated with radiation'' or ''Treated by irradiation.'' The current regulation does not explicitly address the inclusion of additional information that directs attention to, for example, shelf life or food safety. This option would amend the current regulation to include explicit requirements on inclusion of additional information on irradiation benefits. While it is possible that some firms that irradiate food currently include statements of purpose, this option would formally require this inclusion.

Costs: This option would generate costs because firms would be required to relabel their products in order to include statements of purpose. Tables 1 and 2 of this document outline estimated labeling costs for sectors of the food industry that may require relabeling. The food categories included in the table are currently approved for irradiation by FDA.

Table 1 outlines low, medium, and high cost estimates based on a change in the principal display panel. Table 2 outlines low, medium, and high cost estimates based on a change in the information panel or assuming that the irradiation statement is similar in cost to a nutrient content claim or health claim. It is not certain which table most likely represents costs to firms because it is not certain what conditions would make the costs in table 1 more likely or what conditions would make table 2 more likely. Both tables show estimated costs under compliance periods of 12, 24, and 36 months. In both tables 1 and 2, compliance costs decrease as the length of compliance period increases for all product categories because firms can coordinate new changes in labels with already-scheduled changes in labels. In addition, the compliance period affects whether or not firms would incur additional labor costs, such as overtime, and the volume of labeling inventory that would have to be discarded as a result of a new rule.

Cost estimates are shown in two proportions for each compliance period: If 1 percent of the industry irradiates

[5] Now the Government Accountability Office.

[6] It is our understanding that as of 2000 only a very small proportion of poultry (0.002 percent of annual consumption) and no meats were irradiated and available commercially (Ref. 10).

and if 5 percent of the industry irradiates. As can be seen in the tables, industry costs decrease as the number of firms irradiating food decreases. Data on the actual number of firms that irradiate food or will want to irradiate food in the future are not currently available. The agency requests comments on the number of firms or products that would be affected by a new irradiation labeling rule.

The cost model used in this analysis does not include costs for labeling fresh produce without packaging because fresh fruits and vegetables do not have Universal Product Codes that can be scanned. Nonetheless, it is still necessary to estimate costs associated with labeling fresh fruits and vegetables that have been irradiated.

One way of labeling fresh fruits and vegetables is by placing stickers on the produce. While it is not known how many fruit and vegetable manufacturers irradiate or will want to irradiate as a result of this rule, according to the 2002 Census of Manufacturers (Ref. 8), there are 5,836 firms that process fresh fruits and vegetables. As with costs estimates for the other food categories, it is assumed that 1 percent of these firms, or 58, may want to irradiate, or 5 percent of these firms, or 292, may want to irradiate. Our 1 percent and 5 percent assumptions are based on the generally observed very low rate of adoption of irradiation technology in food processing to date. We do not have specific data to estimate the number of firms that will irradiate if this rule is finalized, and we request comment on this assumption.

For firms, there are administrative costs involving the establishment of what the sticker will look like, as well as the costs of finding the printer to produce these stickers. Based on previous estimates of similar costs in the final rule on the Labeling of Juice Products (63 FR 24254; May 1, 1998), the agency estimates these administrative costs to be $100 per firm. In addition, printers levy one time charges for set-up in addition to the basic per unit cost of labels. The agency estimates these costs to be $250 per firm. Table 3A summarizes administrative costs associated with using stickers if 1 percent of the industry irradiates and if 5 percent of the industry irradiates.

In addition to administrative costs, there are labor costs associated with affixing stickers to the fruits and vegetables. The agency estimates the labor cost of applying the labels by multiplying the average agricultural hourly wage ($10.75) (Ref. 8a) by the approximate number of hours needed to label the irradiated fruits and vegetables. Assuming it takes one worker 1 hour to label 240 pounds of fruits or vegetables (4 pounds per minute multiplied by 60 minutes) it would take approximately 6,250 hours to label 1.5 million pounds of fruits and vegetables, the approximate amount of fruits and vegetables irradiated annually in this country. The total labor costs associated with labels would then be $67,188. Table 3B summarizes total labor costs if one worker can label 240 pounds per hour, 360 pounds per hour or 480 pounds per hour. The agency requests comments on costs associated with labeling fresh fruits and vegetables that have been irradiated.

Benefits: A statement regarding the purpose of irradiation would serve to provide more information to consumers than what is currently on the label. To the extent that the addition of the statement of purpose causes people to purchase irradiated products they may have previously avoided, and to the extent that these products have longer shelf life or lower risk of illness, then consumers will benefit. Consumers may look more favorably on irradiated food once they understand the purpose, which in turn, could result in more irradiated food in the market due to the increase in demand. Information may also be a benefit in itself even if purchases do not increase. Research indicates that providing a statement of purpose results in a more positive attitude by consumers toward the purchase of irradiated food (Ref. 3). Furthermore, research indicates that providing information about the benefits of irradiation may increase willingness of consumers to pay for irradiated food (Ref. 4).

TABLE 1.—COST ESTIMATES: IRRADIATION RELABELING, PRINCIPAL DISPLAY PANEL

Food Category	Compliance Period	Percentage of Firms Affected by Rule	Cost Estimates		
			Low	Medium	High
Spices/Seasonings	12 months	1%	$406,553	$581,000	$966,000
		5%	$2,032,033	$2,905,689	$4,831,841
	24 months	1%	$195,967	$279,944	$468,000
		5%	$981,269	$1,400,095	$2,335,798
	36 months	1%	$27,799	$39,650	$66,269
		5%	$138,995	$198,248	$331,343
Shell Eggs	12 months	1%	$236,341	$314,692	$568,084
		5%	$1,181,032	$1,570,997	$2,844,160
	24 months	1%	$144,063	$191,041	$345,471
		5%	$718,210	$955,915	$1,728,457
	36 months	1%	$61,852	$82,324	$149,000
		5%	$309,262	$411,618	$744,275
Dried Vegetables	12 months	1%	$164,604	$218,663	$394,000
		5%	$822,781	$1,094,153	$1,969,567
	24 months	1%	$92,292	$122,838	$222,307
		5%	$461,461	$614,191	$1,110,562
	36 months	1%	$32,092	$42,713	$77,233
		5%	$160,459	$213,566	$386,163
Totals	12 months	1%	$807,498	$1,114,355	$1,928,084
		5%	$4,035,846	$5,570,839	$9,645,568
	24 months	1%	$432,322	$593,823	$1,035,778
		5%	$2,160,940	$2,970,201	$5,174,817
	36 months	1%	$121,743	$164,687	$292,502

TABLE 1.—COST ESTIMATES: IRRADIATION RELABELING, PRINCIPAL DISPLAY PANEL—Continued

Food Category	Compliance Period	Percentage of Firms Affected by Rule	Cost Estimates		
			Low	Medium	High
		5%	$608,716	$823,432	$1,461,781

Note: Cost estimates include administrative, graphic design, prepress, engraving, analytical testing, market testing, and discarded inventory.
Source: RTI International, ''FDA Labeling Cost Model'' RTI Project 06673.010, March 2003.

TABLE 2.—COST ESTIMATES: IRRADIATION RELABELING, INFORMATION PANEL

Food Category	Compliance Period	Percentage of Firms Affected by Rule	Cost Estimates		
			Low	Medium	High
Spices/Seasonings	12 months	1%	$192,245	$285,335	$447,000
		5%	$959,479	$1,426,545	$2,233,436
	24 months	1%	$91,101	$134,964	$213,209
		5%	$455,504	$674,821	$1,065,921
	36 months	1%	$12,860	$19,042	$30,121
		5%	$64,298	$95,208	$150,605
Shell Eggs	12 months	1%	$107,773	$151,940	$254,488
		5%	$538,863	$759,434	$1,273,169
	24 months	1%	$65,539	$92,365	$154,472
		5%	$327,694	$461,827	$774,240
	36 months	1%	$28,221	$39,773	$66,678
		5%	$141,105	$198,863	$333,388
Dried Vegetables	12 months	1%	$76,347	$107,227	$178,332
		5%	$381,735	$536,134	$891,881
	24 months	1%	$42,110	$59,346	$99,492
		5%	$210,549	$296,732	$497,462
	36 months	1%	$14,642	$20,636	$34,595
		5%	$73,212	$103,179	$172,977
Totals	12 months	1%	$376,365	$544,502	$879,820
		5%	$1,880,077	$2,722,113	$4,398,486
	24 months	1%	$198,750	$286,675	$467,173
		5%	$993,747	$1,433,380	$2,337,623
	36 months	1%	$55,723	$79,451	$131,394
		5%	$278,615	$397,250	$656,970

Note: Cost estimates include administrative, graphic design, prepress, engraving, analytical testing, market testing, and discarded inventory.
Source: RTI International, ''FDA Labeling Cost Model'' RTI Project 06673.010, March 2003.

TABLE 3A.—COST ESTIMATES: STICKER ADMINISTRATIVE COSTS

Number of Firms	Administrative Costs	Printing Costs	Total Administrative Costs
1%, or 57	$100	$250	$19,950
5%, or 283	$100	$250	$99,050

TABLE 3B.—COST ESTIMATES: STICKER LABOR COSTS

Pounds Per Hour	Hourly Wage	Hours Needed	Total Labor Cost
240	$10.75	6,250	$67,188
360	$10.75	4,167	$44,792
480	$10.75	3,125	$33,594

Option 4: Maintain the current labeling requirement, but propose to also allow alternate terms to ''Irradiation'' (e.g., ''Pasteurized'')

The current regulation (§ 179.26(c)) states that irradiated food must bear the radura logo and the phrase ''Treated with radiation'' or ''Treated by irradiation.'' Currently, no alternate terms to irradiation are allowed. This option would maintain the requirement that irradiated food must be labeled but allow the label to contain terms other than ''irradiated,'' such as ''pasteurized.'' But the term ''pasteurized'' may be used only if the process meets the definition as provided in section 403(h)(3) of the act.

Costs: This option generates costs because some firms would opt to relabel their products, but it is uncertain how many firms would do this because this option would be voluntary. However, firms would only relabel if they thought doing so would increase profits. Tables 1 and 2 contain cost estimates for the main food categories that may be affected by this option. It is probable that firms would select a 24 to 36 month compliance period to keep costs down by coordinating the relabeling with regular labeling changes.

In the short run, there may be increased consumption of irradiated food if those consumers who do not want irradiated food do not equate the alternative term with irradiation. Also, confusion could result from the use of alternative terms with uncertain meanings, causing some consumers to increase search costs. Research indicates that many consumers regard substitute terms for irradiation to be misleading (Refs. 2 and 5). In the long run (defined here as a time period long enough for consumers to adjust to and understand the meaning of the alternate terms), consumers' distaste for the term ''irradiation'' would extend to alternate terms used in labeling, especially if there is no additional statement of purpose. Once consumers understand that the alternate terms all mean ''irradiation,'' the result would likely be

a return to the baseline number of irradiated products and labels.

Benefits: It is possible that, in the short run, consumers will not understand that the alternate terms mean the same as ''irradiation.'' However, to the extent that the substitution of terms induces consumers to buy relabeled food that they may have previously avoided and to the extent that these products benefit them in terms of safety or longer shelf life, then consumers will benefit from the substitution of terms. In the short run, the quantity of irradiated food supplied may increase in response to increased demand. As previously mentioned, the long run outcome may be the same as the baseline because, over time, consumers will come to understand that any alternate terms have the same meaning as ''irradiation.'' Once consumers understand that the alternate terms have the same meaning as ''irradiation'' they may want to discontinue consumption of the food, resulting in the number of irradiated foods returning to the same number as before the change in terms. This is a result of producers responding to the change in demand by reducing the quantity of irradiated food supplied.

Option 5: The Proposed Regulation

Only those foods treated with irradiation, and in which the irradiation caused a material change in the food such that it would change the characteristics of the food in a way that is not readily apparent to the consumer at the point of purchase must bear: (1) The radura logo and (2) the term ''irradiated'' or a derivative thereof, or an alternate term such as ''pasteurized,'' in conjunction with explicit language describing the change in the food or its conditions of use (e.g., ''irradiated to inhibit sprouting''). If a firm chooses to use an alternate term to ''irradiation'' other than ''pasteurized,'' it must submit a petition to the Secretary (FDA). If a firm wishes to use the term ''pasteurized,'' it must submit a notification including effectiveness data regarding the process or treatment to the Secretary (FDA).

This option deviates from the current regulation (§ 179.26(c)) in two major ways. First, this option would require irradiation labeling only for food items treated with irradiation if irradiation causes a material change in the food or consequences that may result from use of the food. Secondly, this option requires explicit language describing the material change and allows use of alternate terms for irradiation, as long as a petition is approved by the agency or, in the case where ''pasteurized'' is used, a notification is sent to FDA to which the agency does not object. This option allows for more labeling flexibility and it is possible that the radura logo and label statements on some irradiated food, as long as the irradiation caused no material change, could be removed. The number of products that could be marketed without irradiation labeling is uncertain because labeling requirements cannot be made in advance for all products. Rather, the need for labeling must be determined on a case-by-case basis by appropriate testing of the food irradiated under specific conditions, i.e., time and dosage, because the effect of irradiation on the properties of concern depends on the particular food. It is more likely that this option would simply allow firms more flexibility in how they label irradiated food.

Costs: This proposed rule generates costs because it requires firms to relabel some irradiated products. As with other options, Tables 1 and 2 contain cost estimates for relabeling in selected food categories. Note that cost estimates take into account all relabeling costs, including the costs of removing irradiation label statements. The requirement of a material change could reduce the number of products that would need to be labeled, so some firms would be able to remove current irradiation labeling. This rule would generate additional costs because, in order for a firm to be able to use an alternative to the term ''irradiation,'' a firm would have to submit a petition to the agency (as addressed in proposed § 179.26(c)(2)(i)). If it is the case that the desired alternate term is ''pasteurized,'' then, instead of submitting a petition, a firm must notify the agency and also submit effectiveness data on the method used in its process (as addressed in proposed § 179.26(c)(2)(ii)). Firms are not required to use an alternate term. It is assumed that a firm would choose to use an alternate term only if doing so would increase profits.

Based on previous estimates of the cost to prepare a petition or notification, FDA is assuming the average cost to prepare a petition or notification is $84 per hour (Ref. 13). The agency estimates the total cost of a petition or notification as the time needed to prepare the notification or petition multiplied by $84, the approximate cost associated with the person for preparing the notification or petition. In the case where a firm wants to use the term ''pasteurized,'' the agency does not assume this rule generates any additional cost of gathering effectiveness data; that is, presumably the firm will already have data on the effectiveness of its method, or it would not undertake the cost of irradiation. As mentioned earlier, it is not known how many firms that currently irradiate or will irradiate in the future will be required to label a product as irradiated, and will desire to use an alternative to the term ''irradiation.'' Therefore, the cost estimates are based on an estimate of the number of firms manufacturing foods that are currently approved for irradiation choosing to submit a notification or petition.

Table 4 of this document contains the initial cost estimates of preparing a notification or petition. The number of firms is based on the 2002 Census of Manufacturers (Refs. 6, 7, and 8). According to the Census of Manufacturers, there are 275 companies that manufacture spices and extracts, 311 companies that process poultry and shell eggs (the Census of Manufacturers groups poultry and shell egg processing together), and 5,836 firms that process fresh fruits and vegetables, for a total of 6,422 firms. It is possible that 1 percent of, or 64 firms in the industry will want to use an alternate term and it is possible that 5 percent of, or 321 firms in the industry will want to use an alternate term. The average of this range is 193 firms.

Table 5 of this document presents cost estimates of the annual reporting burden for additional product notifications or petitions after the initial compliance period due to, for example, new firms entering into the industry. It is assumed that one petition to use an alternate term other than ''pasteurized'' will be submitted per year. The time estimates for both tables 4 and 5 are taken from section IV of this document. We estimate that the annual notifications would be about 10 percent of the initial number, that is, 10 percent of 193 (the estimate in table 4), or 19 firms.

TABLE 4.—ESTIMATE OF TOTAL COST OF SUBMITTING NOTIFICATION OR PETITION

21 CFR Section	No. of Respondents	Total Hours	Cost Per Hour	Total Cost
179.26(c)(2)(i)	1	150	$84	$12,600

TABLE 4.—ESTIMATE OF TOTAL COST OF SUBMITTING NOTIFICATION OR PETITION—Continued

21 CFR Section	No. of Respondents	Total Hours	Cost Per Hour	Total Cost
179.26(c)(2)(ii)	193	28,950	$84	$2,431,800
Total				$2,444,400

TABLE 5.—ESTIMATED ANNUAL COST OF SUBMITTING NOTIFICATION OR PETITION

21 CFR Section	No. of Respondents	Total Hours	Cost Per Hour	Total Cost
179.26(c)(2)(i)	1	150	$84	$12,600
179.26(c)(2)(ii)	19	2,850	$84	$239,400
Total				$252,000

If irradiation causes no material change in the food, irradiation labeling would be removed under this option. Removing irradiation labeling could cause increases in search costs for consumers who desire to avoid purchasing irradiated goods and must find alternative sources to maintain knowledge of producers that irradiate their products.

Some producers may alter their products' labels to use a term other than irradiated (e.g. ''pasteurized''). However, it is uncertain how many producers would use alternate terms. Again, the use of alternative labels would generate potential costs because some consumers may wish to avoid irradiated products. As mentioned before, research indicates many consumers regard substitute terms for irradiation to be misleading (Refs. 2 and 5). These individuals would have to increase their search efforts in order to continue to be informed about approved alternate terms to irradiation. We request comment on the potential for this proposed rule if finalized to increase search costs, particularly for consumers and retailers who desire non-irradiated foods.

Benefits: This proposed rule generates benefits because it could allow consumers to make more informed decisions about the food they purchase. If the addition of a statement of purpose causes people to buy relabeled irradiated products that they may have previously avoided and if these products have, for example, longer shelf life or lower risk of illness, then consumers will benefit. If, as a result of this proposed rule, consumers look more favorably on irradiated foods, the supply of such foods may increase. If retailers are more willing to carry relabeled irradiated products, then consumers benefit from the added opportunity to buy these products.

As mentioned in the costs section of this option, if irradiation causes no material change, it is possible that some products would no longer have to bear the irradiation label statement or the radura logo, but it is uncertain how many products would fall into this category. For producers who voluntarily choose the no-label option, private benefits exceed private costs, since they no longer are required to continue with the existing labeling. That is, a firm would choose the no-label option if it believes doing so will increase profits. Reiterating the idea that the supply of irradiated food may increase as a result of this rule, it is possible that some manufacturers not currently using irradiation as a safety tool (because of the current labeling requirement) may opt to start using irradiation in order to enhance the safety of their products, if there is no material change in the product. Again, firms will only start using irradiation if they believe doing so will increase profits. As already pointed out, however, there are potential search costs for some customers.

This analysis also applies to those firms who choose alternate terms for irradiation. Private benefits will exceed private costs for firms that voluntarily choose alternate terms for irradiation, because they will no longer be required to continue using existing labeling. These firms will only choose alternate terms to irradiation if they believe doing so will increase profits. Again, this use of alternate terms can result in the previously mentioned increase in search costs for consumers who desire to avoid irradiated goods.

If the removal of explicit language indicating that a food has been irradiated causes people to buy irradiated products that they previously avoided, and if these products have lower prices or higher quality, then some consumers will benefit from the removal of information. Also, if retailers are more willing to carry unlabeled irradiated products at lower prices, then all consumers benefit from the lower prices. But it is uncertain that unlabeled irradiated products will be offered for lower prices than products that are not irradiated, because the irradiation process itself is not costless. If irradiation increases product quality but also increases the cost of production, then prices of irradiated products could be higher than the same non-irradiated products, with or without labels.

C. Summary of Options

Table 5A of this document summarizes the costs and benefits of each option analyzed. Costs are given based on the assumption that 1 percent of firms irradiate and relabel (at the medium cost level) using a 2-year compliance period if the option requires relabeling and a 3-year compliance period if relabeling is permitted voluntarily. For Option 5, it also assumes that 1 percent of firms prepare a notification to use the term ''pasteurized'' in the first year and 1 firm petitions to use another alternative term in the first year. The range of costs represents our uncertainty about the need for changes to the principal display panel or the information panel and the number of pounds of fresh fruits and vegetables that can be stickered per hour. For Option 5, the quantified costs are likely to be less than listed because some firms would be able to remove the irradiation labeling when it results in no material change when it is least costly for them to do so and will not need to submit notifications or petitions.

TABLE 5A.—SUMMARY OF COSTS AND BENEFITS OF OPTIONS

	Quantified Costs	Unquantified Costs	Unquantified Benefits
Option 1 (baseline)	0	0	0
Option 2	0	Greatest increase in search costs	Most additional labeling flexibility, potentially longer shelf-life
Option 3	$341,000 - $681,000	0	Most additional information for consumers
Option 4	$133,000 - $252,000	Increased search costs	Additional labeling flexibility
Option 5 (the proposed rule)	Less than $2,785,400 - $3,125,400	Lowest non-zero increase in search costs	Additional information for consumers, Least non-zero additional labeling flexibility

We request comments on the estimates for these options and specifically on the following three issues:

1. The number of firms or products that would be affected by a new irradiation rule.
2. The number of firms that would begin irradiating products as a result of the various options described here.
3. Whether some industry sectors should be given more time to comply than others to reduce the economic impact on them.

D. Small Entity Analysis

FDA has examined the economic implications of this proposed rule as required by the Regulatory Flexibility Act (5 U.S.C. 601–612). If a rule has a significant economic impact on a substantial number of small entities, the Regulatory Flexibility Act requires agencies to analyze regulatory options that would lessen the economic effect of the rule on small entities. It is not known how many small firms currently irradiate food or will want to irradiate food. If small firms are using this technology, this proposed rule may have a significant economic impact on a substantial number of small entities. The agency requests comments on how this proposed rule will impact small firms.

Under contract, Eastern Research Group developed a model framework for estimating regulatory impacts on small businesses. The model is designed to accommodate a variety of potential regulatory activities, ranging from Hazard Analysis Critical Control Point (HACCP) to product labeling.

Using the 2002 Economic Census and other data, the model estimates the cash flows of representative establishments of varying class sizes of food manufacturers. Based on post-regulation cash flow and distribution of income for each model facility, the model generates the percentage of facilities in each model class that are vulnerable to closure. The model allows the agency to (1) Predict the probability and frequency of small business failure as a result of FDA regulations and (2) estimate the effects of various forms of regulatory relief on the survival of small businesses on a per-establishment basis.

Cost estimates produced by the FDA Labeling Cost Model were used to help generate estimates of the average relabeling cost for firms in two of the four food categories examined here: spices/seasonings and dried vegetables. The middle estimated costs in each food category were divided by the estimated affected stockkeeping units (SKUs) in each food category to arrive at average cost per SKU. Affected SKUs per category are then divided by total number of firms in each category to arrive at average number of affected SKUs per firm. The number of firms in each food category comes from the Ready-to-Eat Food Manufacturing Industry category in FDA's Small Business Impact Model (Ref. 9). We use these estimates to calculate cost per firm using the following formula:

Cost/Firm = (Average SKUs per firm) x (Average Middle Relabeling Cost/SKU)

This formula allows us to estimate the approximate average relabeling costs for firms in each food category. Keep in mind these are merely estimates and cost structures are treated identically across firms. That is, we assume that costs for small firms are similar to costs for large firms. The average relabeling costs for compliance periods of 12, 24, and 36 months were then entered into the Small Business Impact Model to estimate the number of firms at risk for negative cash flow, assuming all firms in each category must relabel. The results of these estimates are presented in tables 6 and 6A of this document. The table is divided into two sections, one for estimates if the information panel is affected and another for the principal display panel.

TABLE 6.—ESTIMATES OF FIRMS AFFECTED BY THE IRRADIATION RULE—CHANGES IN INFORMATION PANEL

Food Category	Compliance Period	Firms with less than 20 Employees		Firms With 20 to 499 Employees		Firms With 500+ Employees	
		Affected Firms	At-Risk Firms[1]	Affected Firms	At-Risk Firms[1]	Affected Firms	At-Risk Firms[1]
Spices/ Seasonings	12 months	139	18	133	0	2	0
	24 months	139	7	133	0	2	0
	36 months	139	1	133	0	2	0
Dried Vegetables	12 months	23	8	25	0	1	0
	24 months	23	3	25	0	1	0
	36 months	23	2	25	0	1	0

[1] Note: An ''at-risk'' firm is one that could potentially suffer from negative cash flow as a result of this proposed rule.

TABLE 6A.—ESTIMATES OF FIRMS AFFECTED BY THE IRRADIATION RULE—CHANGES IN PRINCIPAL DISPLAY PANEL

Food Category	Compliance Period	Firms with less than 20 Employees		Firms With 20 to 499 Employees		Firms With 500+ Employees	
		Affected Firms	At-Risk Firms[1]	Affected Firms	At-Risk Firms[1]	Affected Firms	At-Risk Firms[1]
Spices/ Seasonings	12 months	139	39	133	1	2	0
	24 months	139	11	133	0	2	0
	36 months	139	2	133	0	2	0
Dried Vegetables	12 months	23	8	25	0	1	0
	24 months	23	8	25	0	1	0
	36 months	23	3	25	0	1	0

[1] Note: An ''at-risk'' firm is one that could potentially suffer from negative cash flow as a result of this proposed rule.

The numbers of at-risk firms in the table are estimates generated by the model. These estimates are not based on specific data about the number of small firms affected, because there are no data available; however, they illustrate the idea that small firms, especially firms with fewer than 20 employees, could potentially be adversely affected by this proposed rule. For example, in the dried vegetable category, for a compliance period of 12 months, if as the model estimates, 23 firms would be affected, approximately 8 of these firms (or around 35 percent) would be at risk for negative cash flow as a result of this rule. However, for firms with less than 20 employees, the number of at risk firms decreases as the length of the compliance period increases. As illustrated in tables 1 and 2, when compliance periods increase, costs decrease because firms can coordinate new changes in food labels with already-scheduled changes in labels. By contrast, the model generates no at-risk firms among firms with 500+ employees, regardless of the compliance period. This result is important because the industry is characterized by a large number of small entities. The most effective regulatory relief for small firms would be extended compliance periods. As shown in tables 6 and 6A, as the compliance period increases from 12 to 36 months, the number of small firms at-risk virtually disappears.

Firms producing shell eggs are not included in the Ready-to-Eat Application of the Small Business Impact Model because eggs are not considered ready to eat. Therefore, it is not possible to estimate the number of at-risk firms. Nonetheless, small firms producing shell eggs must still be addressed in this analysis. According to the 2002 Census of Manufacturers (Ref. 6), there are 311 companies that process poultry and shell eggs. Of this number, about 25 percent, or 79 firms have 20 employees or less. Again, it is not known how many processors irradiate or will want to irradiate as a result of this rule. Therefore, we will assume this rule could affect 1 percent, or approximately 1 firm.

Firms processing fresh fruits and vegetables are also not included in the Small Business Impact Model. Again, it is not possible to estimate the number of at-risk firms. According to the 2002 Census of Manufacturers, there are 5,836 firms that process fresh fruit and vegetables. Because firm size for firms that process fresh fruits and vegetables is not yet available for the 2002 Census of Manufacturers, we use data from the 1997 Census of Manufacturers that 93 percent of these firms are single unit firms. Therefore, we estimate that there are 5,427 single unit firms that process fresh fruit and vegetables. As with the other food categories, it is not known how many of these firms irradiate or will want to irradiate as a result of this rule. Therefore, we will assume this rule could affect 1 percent, or approximately 54 firms. The agency requests comments on the number of small shell egg producers and fresh fruit and vegetable producers that could be affected by this rule.

The effects on small businesses depend also on whether the labeling change is required or voluntary. If, for example, the labeling change is to allow an alternate term, or to remove the current label, the small business would do so only if it did not impose a burden. For required labeling changes, however, the labeling costs could indeed put additional firms at risk of going out of business. The length of the compliance period for labeling requirements is the most important variable affecting the burden. The other important factor is how much of the label needs redesigning. If the labeling change is similar to a change in the information panel, and if small businesses are given at least 36 months to comply, few will be at risk.

The agency requests comments on the likely effect on small firms as a result of this proposed rule, and on the effects of longer compliance periods for these firms.

E. Unfunded Mandates Reform Act of 1995

Section 202(a) of the Unfunded Mandates Reform Act of 1995 (Public Law 104–4) requires that agencies prepare a written statement, which includes an assessment of anticipated costs and benefits, before proposing ''any rule that includes any Federal mandate that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more (adjusted annually for inflation) in any one year.'' The current threshold after adjustment for inflation is $122 million, using the most current (2005) Implicit Price Deflator for the Gross Domestic Product. FDA does not expect this proposed rule to result in any 1-year expenditure that would meet or exceed this amount.

IV. Paperwork Reduction Act of 1995

This proposed rule contains information collection provisions that are subject to review by OMB under the Paperwork Reduction Act of 1995 (the PRA) (44 U.S.C. 3501–3520). A description of these provisions is given below with an estimate of the reporting burden. Included in the estimate is the time for reviewing instructions, searching existing data sources, gathering and maintaining the information and data needed and completing and reviewing each collection of information.

Title: Notice Concerning the Submission of Information to Use an Alternative to ''Irradiation''

Description: In this proposed rule, FDA is proposing to require the submission to the agency of data and information regarding the use of alternate terms to the word ''irradiated'' in foods that have been treated by irradiation using radioactive isotope,

electronic beam, or x-ray. FDA is proposing that an alternate term may be used in lieu of ''irradiated'' if its use is approved in response to a petition that has been submitted to FDA. If the desired alternate term is ''pasteurized,'' a notification must be sent to the Secretary (FDA) that includes effectiveness data to show that the process or treatment meets the requirements of section 403(h)(3) of the act.

Description of Respondents: Manufacturers that irradiate food and desire to use an alternate term to ''irradiation.''

FDA estimates the burden of this collection of information as follows:

TABLE 7.—ESTIMATED ONE-TIME REPORTING BURDEN[1]

21 CFR Section	No. of Respondents	Frequency of Response	Total Responses	Hours Per Response	Total Hours
179.26(c)(2)(i)	1	1	1	150	150
179.26(c)(2)(ii)	193	1	193	150	28,950
Total					29,100

[1]There are no capital costs or operating and maintenance costs associated with this collection of information.

TABLE 8.—ESTIMATED ANNUAL REPORTING BURDEN[1]

21 CFR Section	No. of Respondents	Frequency of Response	Total Responses	Hours Per Response	Total Hours
179.26(c)(2)(i)	1	1	1	150	150
179.26(c)(2)(ii)	19	1	19	150	2,850
Total					3,000

[1]There are no capital costs or operating and maintenance costs associated with this collection of information.

Tables 7 and 8 of this document describe the reporting burden as a result of the provisions set forth in this proposed rule. Table 7 shows the estimated one time reporting burden after the regulation initially goes into effect. Table 8 shows the estimated annual reporting burden, perhaps due to firms entering into the industry and/or currently existing firms deciding to irradiate at a later date. The agency does not know how many firms will submit a notification or a petition to the agency to use an alternate to the term ''irradiation.'' It is also not known how many firms currently irradiate food they manufacture, although it is known that the amount of food irradiated each year is very small and there is only one facility that can irradiate food. However, it is assumed that most firms wishing to use an alternate term will choose to use ''pasteurized'' and submit a notification to FDA along with effectiveness data. It is also assumed that one firm per year will submit a petition to use an alternate term other than ''pasteurized'' as shown in the row corresponding to proposed § 179.26(c)(2)(i) in table 7. Proposed § 179.26(c)(2)(ii) addresses notifications. The number of firms is based on the 2002 Census of Manufacturers (Refs. 6, 7, and 8). According to the Census of Manufacturers, there are 275 companies that manufacture spices and extracts, 311 companies that process poultry and shell eggs (the Census of Manufacturers groups poultry and shell egg processing together), and 5,836 firms that process fresh fruits and vegetables, for a total of 6,422 firms. Table 7 shows the number of respondents presented as an average, based on percentages of total firms that process shell eggs, spices, and fruits and vegetables, the three categories of FDA-regulated foods that are currently approved for irradiation. It is possible that 1 percent of, or 64 firms in the industry will want to use an alternate term and it is possible that 5 percent of, or 321 firms in the industry will want to use an alternate term. The average of this range is 193 firms. Submission of the notification is voluntary because the proposed rule does not require all firms to submit notifications, only those firms that will be required to label a product as ''irradiated'' and desire use of an alternative to the term ''irradiation''. Therefore, it is assumed that there will be no annual reporting burden for this rule for products that have already submitted notifications.

Based on previous estimations of preparing notifications and preparing petitions, FDA is estimating that the time needed to prepare a notification is 150 hours. The agency already has a process for submitting citizen petitions, the burden of which is reported and approved under § 10.30. However, given some of the controversy surrounding irradiation and the use of alternative terms to irradiation, we expect more documentation and more hours spent on these petitions associated with irradiation labeling. Therefore, the agency is assuming submitting a petition will take a total of 190 hours. It is estimated that 40 of these hours are specific to the citizen petition process reported under § 10.30, with an additional 150 hours specific to the issues associated with irradiation labeling. It is this additional burden that is reported in table 7.

The annual burden following the initial round of submissions would consist of submissions for additional products, perhaps as a result of market entry. This burden is shown in table 8. Again, we also assume that, each year, one firm will petition the agency to use an alternate term other than ''pasteurized,'' in response to proposed § 179.26(c)(2)(i). We do not know how many additional firms will submit notifications in response to proposed § 179.26(c)(2)(ii) each year, so table 8 assumes the number of additional firms will be 10 percent of the firms reported in table 7. We also assume that there will not be an additional recordkeeping burden associated with this rule, as it is assumed that firms already have the effectiveness data required by the agency for inclusion in the notification.

In compliance with the PRA (44 U.S.C. 3507(d)), the agency has submitted the information collection provisions of this proposed rule to OMB for review. Interested persons are requested to submit comments regarding

information collection to OMB (see **ADDRESSES**).

V. Analysis of Environmental Impact

The agency has determined under 21 CFR 25.30(k) that this action is of a type that does not individually or cumulatively have a significant effect on the human environment. Therefore, neither an environment assessment nor an environmental impact statement is required.

VI. Federalism

FDA has analyzed this proposed rule in accordance with the principles set forth in Executive Order 13132. FDA has determined that the proposed rule does not contain policies that have substantial direct effects on the States, on the relationship between the National Government and the States, or on the distribution of power and responsibilities among the various levels of government. Accordingly, the agency tentatively concludes that the proposed rule does not contain policies that have federalism implications as defined in the order and, consequently, a federalism summary impact statement is not required.

VII. References

The following references have been placed on display in the Division of Dockets Management (see **ADDRESSES**) and may be seen by interested persons between 9 a.m. and 4 p.m., Monday through Friday. (FDA has verified the Web site address, but we are not responsible for subsequent changes to the Web site after this document is published in the **Federal Register**.)

1. Conference Report on S. 830, Food and Drug Administration Modernization Act of 1997, 143 Cong. Rec. H10452, 10477, (November 9, 1997).

1a. Prakash, Anuradha and Denise Foley, ''Improving Safety and Extending Shelf Life of Fresh-Cut Fruits and Vegetables Using Irradiation in Irradiation of Food and Packaging; Recent Developments,'' ACS Symposium Series 875, V. Komolprasert and K. Morehouse editors, American Chemical Society, Washington, DC 2004.

1b. Kader, Adel A., ''Potential Applications of Ionizing Radiation in Postharvest Handling of Fresh Fruits and Vegetables,'' *Food Technology*, 117–121, June 1986.

2. ORC Macro, ''Consumers' Understanding of Food Irradiation Labeling,'' Focus Group Report, December 2001.

3. Schutz, Howard G., Christine M. Bruhn and Katherine V. Diaz-Knauf, ''Consumer Attitude Toward Irradiated Foods: Effects of Labeling and Benefits Information,'' Food Technology 43, (October 1989): 80–86.

4. Fox, John A., Dermot J. Hayes, Jason F. Shogren, ''Consumer Preferences for Food Irradiation: How Favorable and Unfavorable Descriptions Affect Preferences for Irradiated Pork in Experimental Auctions,'' *The Journal of Risk and Uncertainty*, 24:1 (2002): 75–95.

5. Cates, Sheryl C., et al., ''Consumer Research on Food Safety Labeling Features for the Development of Responsive Labeling Policy,'' RTI, March 22, 2002.

6. ''United States Census Bureau, Poultry Processing: 2002 Economic Census Manufacturing Industry Series,'' available from *http://www.census.gov/prod/ec02/ec0231i311615.pdf* (accessed October 20, 2006).

7. ''United States Census Bureau, Spice and Extract Manufacturing: 2002 Economic Census Manufacturing Industry Series,'' available from *http://www.census.gov/prod/ec02/ec0231i311942t.pdf* (accessed October 20, 2006).

8. ''United States Census Bureau, Comparative Statistics: 2002 Economic Census Manufacturing Industry Series,'' p. 9, available from *http://0-www.census.gov.mill1.sjlibrary.org/prod/ec02/ec0200ccomp.pdf* (accessed October 20, 2006).

8a. *Private Industry by State and 6-Digit NAICS Industry: Establishments, Employment, and Wages, 2004 Annual Averages*, *http://www.bls.gov/cew/ew04sector11.pdf*, December 30, 2005.

9. Eastern Research Group, Inc., ''Model for Estimating the Impacts of Regulatory Costs on The Survival of Small Businesses and its Application to Four FDA-Regulated Industries,'' Contract No. 223–01–2461, June 7, 2002.

10. General Accounting Office, ''Food Irradiation: Available Research Indicates That Benefits Outweigh Risks,'' GAO/RCED–00–217, August, 2000.

11. RTI International, ''FDA Labeling Cost Model,'' RTI Project Number 06673.010, January 2003.

12. Office of Management and Budget, ''GDP and Deflators Used in the U.S.,'' Budget of the United States Government Fiscal Year 2004, Historical Table 10.1, 2003.

13. U.S. Food and Drug Administration, Substances Generally Recognized as Safe: Notification Procedure, OMB No. 0910–0342, Supporting Statement available from *http://www.fda.gov/OHRMS/DOCKETS/98fr/05n-0457-ss00001.pdf*.

List of Subjects in 21 CFR Part 179

Food additives, Food labeling, Food packaging, Radiation protection, Reporting and recordkeeping requirements, Signs and symbols.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs, it is proposed that 21 CFR part 179 be amended as follows:

PART 179—IRRADIATION IN THE PRODUCTION, PROCESSING AND HANDLING OF FOOD

1. The authority citation for 21 CFR part 179 continues to read as follows:

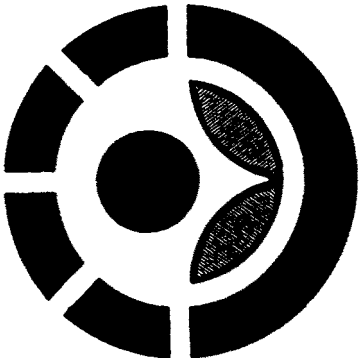
Authority: 21 U.S.C. 321, 342, 343, 348, 373, 374.

2. Section 179.26 is amended by revising paragraph (c)(1); by redesignating paragraphs (c)(2) and (c)(3) as paragraphs (c)(3) and (c)(4), respectively; by revising newly redesignated paragraph (c)(3); and by adding new paragraph (c)(2) to read as follows:

§ 179.26 Ionizing radiation for the treatment of food.

* * * * *

(c) *Labeling.* (1) The label and labeling of a retail package of a food irradiated in conformance with paragraph (b) of this section that has, as a result of the irradiation, undergone a material change in the characteristics of the food or in its consequences of use shall bear the following logo along with



the statement ''irradiated,'' or any derivatives of the term ''irradiated'' (e.g., ''irradiation,'' ''irradiate,'' ''radiation,'' etc.) or an alternate term as provided in paragraph (c)(2) of this section, in conjunction with language describing the material change in the characteristics of the food or its use. The logo shall be placed prominently and conspicuously in conjunction with the required statement. The radiation disclosure statement is not required to be more prominent than the declaration of ingredients required under § 101.4 of this chapter. As used in this provision, the term ''radiation disclosure statement'' means a written statement that discloses that a food has been intentionally subjected to irradiation and identifies the material change in the characteristics of the food or the consequences that may result from its use as a result of the irradiation.

(2) An alternate term may be used in lieu of ''irradiated,'' or any of its derivatives, if it meets the following provisions.

(i) A term that is not false or misleading in any material respect may be used in lieu of ''irradiated,'' or any of its derivatives, if its use is approved in response to a petition that has been submitted to FDA using the procedures under § 10.30 of this chapter for approval of the alternate term, or, if use of the term ''pasteurized'' is permissible

under the requirements in paragraph (c)(2)(ii) of this section. The petition should include all relevant information and views on which the petitioner relies, including any data, e.g., qualitative or quantitative consumer research, that show consumer understanding of the purpose and intent of the alternative labeling.

(ii) The term ''pasteurized'' may be used in lieu of ''irradiated'' or any of its derivatives if the irradiation process is:

(A) Reasonably certain to achieve destruction or elimination in the food of the most resistant microorganism of public health significance that is likely to occur in the food;

(B) At least as protective of the public health as a process or treatment that is defined as pasteurization in this chapter;

(C) Effective for a period that is least as long as the shelf life of the food when stored under normal and moderate abuse conditions; and

(D) The subject of a notification to the Secretary of Health and Human Services (the Secretary) that includes effectiveness data regarding the process or treatment and the Secretary has not made a determination in 120 days after the receipt of the notification that the process or treatment involved has not been shown to meet the requirements provided in paragraph (c)(2)(ii)(A), (B), and (C) of this section.

(3) For an irradiated food not in packaged form that has, as a result of the irradiation, undergone a material change in its characteristics or conditions of use, the required logo and the following disclosure statements, ''irradiated,'' or any of its derivatives, or an alternate term as provided in paragraph (c)(2) of this section in conjunction with language describing the material change in the characteristics of the food or conditions of use as a result of the irradiation, shall be displayed to the purchaser with either of the following:

(i) The labeling of the bulk container plainly in view or

(ii) A counter sign, card, or other appropriate device bearing the information that the product has been treated with radiation. As an alternative, each item of food may be individually labeled. In either case, the information must be prominently and conspicuously displayed to purchasers. The labeling requirement applies only to a food that has been irradiated, not to a food that merely contains an irradiated ingredient but that has not itself been irradiated.

* * * * *

Dated: March 27, 2007.

Jeffrey Shuren,

Assistant Commissioner for Policy.

[FR Doc. 07–1636 Filed 4–3–07; 8:45 am]

BILLING CODE 4160–01–S

LIBRARY OF CONGRESS

Copyright Office

37 CFR Part 202

[Docket No. RM 2007–3]

Registration of Claims to Copyright—Renewals

AGENCY: Copyright Office, Library of Congress.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Copyright Office is proposing to amend its regulations governing applications for registration of claims to the renewal term of copyright. This notice seeks public comment on the proposed amended regulations, which will take into account the fact that, since January 1, 2006, all applications for renewal have necessarily related to works which are subject to automatic renewal and, thus, are already in their renewal terms, making impossible any 28th– year registration of claims to the renewal term.

DATES: Comments are due May 4, 2007.

ADDRESSES: If hand delivered by a private party, an original and five copies of a comment or reply comment should be brought to Library of Congress, U.S. Copyright Office, 2221 S. Clark Street, 11th Floor, Arlington, VA. 22202, between 8:30 a.m. and 5 p.m. The envelope should be addressed as follows: Office of the General Counsel, U.S. Copyright Office. If delivered by a commercial courier, an original and five copies of a comment or reply comment must be delivered to the Congressional Courier Acceptance Site (''CCAS'') located at 2nd and D Streets, NE, Washington, DC between 8:30 a.m. and 4 p.m. The envelope should be addressed as follows: Office of the General Counsel, U.S. Copyright Office, LM–401, James Madison Building, 101 Independence Avenue, SE, Washington, DC. Please note that CCAS will not accept delivery by means of overnight delivery services such as Federal Express, United Parcel Service or DHL. If sent by mail (including overnight delivery using U.S. Postal Service Express Mail), an original and five copies of a comment or reply comment should be addressed to U.S. Copyright Office, Copyright GC/I&R, P.O. Box 70400, Southwest Station, Washington, DC 20024.

FOR FURTHER INFORMATION CONTACT: Nanette Petruzzelli, Special Legal Advisor for Reengineering, P.O. Box 70400, Washington, DC 20024–0400. Telephone: 202–707–8350. Telefax: 202–707–8366.

SUPPLEMENTARY INFORMATION:

I. Background

The 1976 Copyright Act, 17 U.S.C. 101, et. seq., carried over provisions for the continued protection of certain works first published or registered for copyright under the 1909 Copyright Act. Reenacting and preserving the provisions of section 24 of the 1909 law for all works which were then in their first term of copyright protection, Section 304(a) of Title 17 as originally enacted in 1976 provided that renewal registration had to be made during the 28th year of the original term of copyright in order to secure the additional (then 47) years of renewal–term protection. 17 U.S.C. 304(a) (1976).

In 1992, Congress enacted a revision of section 304(a) of Title 17 which made renewal copyright automatic for works first published or registered from January 1, 1964, through December 31, 1977. This amendment allowed the renewal right to vest without registration of: [a] the claim to copyright during the original, 28–year term; or, [b] the claim to renewal copyright during the year immediately prior to the beginning of the renewal term (*i.e.*, during the 28th year); or, [c] the claim to renewal copyright during the renewal term. Pub. L. No. 102–307, 106 Stat. 264, enacted June 26, 1992. In order to encourage renewal registration and provide a public record of renewal rights, however, Congress also amended section 304(a) to provide certain benefits to a party who undertook the renewal registration within the 28th year of the original term of copyright. These benefits for works with timely renewal registrations include:

1. A certificate of registration constitutes prima facie evidence as to the validity of the copyright during its renewal term and of the facts stated in the certificate. 17 U.S.C. 304(a)(4)(B).

2. A derivative work prepared under the authority of a grant of a transfer or license of copyright in a work made before the expiration of the original term of copyright may not continue to be used under the terms of the grant during the renewal term without the authority of the owner of the renewal copyright. 17 U.S.C. 304(a)(4)(A).

3. A renewal copyright vests upon the beginning of the renewal term in the

party who was entitled to claim the renewal of copyright at the time the application was made as provided under 17 U.S.C. 304(a)(2)(A)(i) and (B)(i).

Registration of a claim to the renewal term has also been possible since the 1992 amendment at any time during the renewal term, *i.e.*, at any time beyond the 28th year of the original term of copyright. 17 U.S.C. 304(a)(3)(A)(ii). Such renewal registration may be made whether or not an original–term registration was previously made. If no original–term registration was made, the renewal term applicant must provide information, under the provision of 17 U.S.C. 409 (11), regarding the original term of copyright. Such information must demonstrate that the work submitted for renewal registration complies with all requirements of the 1909 Act with respect to the existence, ownership, or duration of the copyright for the original term of the work. The Addendum to Form RE has been used to provide this information to the Copyright Office.

The 1992 amendment further provided that, where no renewal registration has been made in the name of a party identified as entitled to the renewal right in the statute at 304(a)(1)(B) and (C), an application form may be filed at any time during the renewal term by any successor or assignee of such statutorily–enumerated party. Section 304(a)(3).

II. End of 28th–Year Renewal Registration

The Copyright Act of 1909 ceased to be effective on January 1, 1978. For all works published before January 1, 1978, where the year date in the copyright notice on published copies or phonorecords distributed by authority of the copyright owner was earlier than the year date of first publication, claims to renewal copyright must have been registered during the last year of the original copyright term as that term was computed from the year date in the copyright notice. For purposes of renewal registration, this year period began on December 31 of the 27th year from the year date appearing in the notice and ran through December 31 of the 28th year from the year date appearing in the notice rather than being computed from the year date of actual first publication. This ameliorative principle arose from case law under the 1909 Act and essentially benefitted the copyright owner by providing an alternative to the complete loss of copyright in instances of a wrong, *i.e.*, earlier, year date in the copyright notice. Further, for works governed by the 1909 copyright law, in effect until December 31, 1977, the original copyright term for a published work was computed from the date of first publication; the original term for a work first registered in unpublished form was computed from the date of registration in the Copyright Office.

On January 1, 1978, the Copyright Act of 1976, Pub. L. No. 94–553, 90 Stat. 2541 (October 19, 1976), became effective. The extensively revised copyright law provided that any work unpublished and not registered as of January 1, 1978, or published on or after that date, was to be governed by the 1976 statute and was to receive a term of protection provided by section 302 of the statute. However, for any copyright, the first term of which was subsisting on January 1, 1978, such term was to last 28 years with a possibility of a 47–year renewal term. Further, Pub. L. No. 105–298, 112 Stat. 2827, enacted October 27, 1998, changed the renewal term for works under copyright protection as of that date from 47 to 67 years.

Thus, works first published or registered for their original term of copyright on or before December 31, 1977, constitute the category of works for which the renewal structure is applicable. Any such work could have an original term of copyright of 28 years, assuming compliance with all applicable requirements of the 1909 statute, and no work governed by the carried–over renewal provisions of section 304(a) of Title 17 may possess an original term of copyright extending beyond December 31, 2005, *i.e.*, 28 years after December 31, 1977. Thus, December 31, 2005, was the last day on which a work first published or originally registered as unpublished during the effective period of the 1909 copyright law could have been submitted for renewal registration during the 28th year of its original term of copyright and be eligible for the benefits listed above.

III. Continuation of Post–28th Year Renewal Registration

After January 1, 2006, works that were first published or registered as unpublished for the original term of copyright between 1964 and 1977 will continue to be amenable to renewal registration. Concerning works eligible for renewal registration since 1992, statutory claimants and successors or assignees of such statutory claimants may file applications for the renewal term.

A claim to the renewal term must be registered in the name of the statutory claimant in whom the renewal copyright vested on the last day of the original term of copyright. 17 U.S.C. 304(a)(2)(A)(ii) and (2)(B)(ii). This is true even when that claimant is no longer the owner of the copyright in the renewal term. If the statutory claimant in whom the renewal vested is the current owner and that claimant is submitting the renewal claim, that fact must be indicated on the renewal application.

Where there is a successor or assignee of any statutory renewal claimant (the party who was the owner of the renewal term as determined on the last day of the original 28–year term of copyright), the successor or assignee may file the renewal application. 17 U.S.C. 304(a)(3)(A)(ii). Consistent with the Offices long–standing regulation at 37 CFR 202.3(b)(10), as a general rule, only one registration can be made for the same version of a particular work. This rule applies to renewal claims, including those filed by a successor or assignee. For example, if a successor–in–interest filed a renewal claim in 2006 and later assigned his interest to someone else, that person could not file a renewal claim.

In the case of an application filed by a successor or assignee, the renewal application must identify the party in whom the renewal copyright vested by virtue of 17 U.S.C. 304(a)(1)(B) and (C) but in whose name no previous renewal registration has been made; must indicate the basis upon which copyright in the renewal term vested in that party; and must identify the party filing as successor or assignee of the statutory claimant under 17 U.S.C. 304(a)(3) and the manner by which such successor/assignee secured the renewal copyright. When such an application has been filed by a successor or assignee in the name of the statutory claimant as described in 17 U.S.C. 304(a)(1)(B) and (C), the Office will generally not accept subsequent claims filed by other successors or assignees whose rights are derived from the same statutory claimant.

Where a successor or assignee claims the renewal right from the same statutory claimant as does another successor or assignee, the Copyright Office may, however, inquire concerning the particular situation and, if appropriate, may allow adverse renewal claims from both successors/assignees to be placed on the public record. Applications in which two or more persons or organizations adversely claim the copyright to the renewal term in a particular work will be handled as the Office's *Compendium of Copyright Practices, Compendium II (1984)*, § 108.06, indicates: adverse claims will be registered if, after the Office inquires

concerning the claims, each claim, on its own merits, is determined to meet all applicable statutory and regulatory requirements. In such a case, correspondence between the parties filing competing renewal claims and the Copyright Office will be maintained within Office records and subject to public inspection according to regulations found at 37 CFR 201.2. In cases where adverse renewal claims are not accepted by the Copyright Office, however, if a public record of renewal ownership is sought by particular successors or assignees of the same statutory claimant as indicated in the filing of a previous claim by another successor or assignee, the document of transfer of the renewal copyright may be recorded in the Copyright Office.

IV. Renewal Registration Procedures

Under the proposed amendment, the Copyright Office will provide a revised application form for the registration of renewal claims. The proposed revised Form RE, as well as the proposed revised Form RE/CON (for use when additional information must be supplied) and Form RE/ADDENDUM (to be filed if the work, or the collective work in which it was first published, was not registered during the original term) may be viewed on the Copyright Office website at www.copyright.gov/proposedforms. Following issuance of a final rule, these new forms will be available on the Copyright Office website at www.copyright.gov as well as through postal mail upon request. Any requests to the Copyright Office for application forms for registration of claims to the renewal term will be filled with the newly revised form; the forms currently in use will be obsolete and the new forms must be used to file such renewal claims.

One of the major changes to the form will facilitate the filing of applications by successors or assignees of the statutory renewal claimants listed at 17 U.S.C. 304(a)(1)(B) and (C). During the past several years, those successors or assignees of statutory claimants who wished to file an application to the renewal term, 17 U.S.C. 304(a)(3)(ii), had to seek advice from the Copyright Office because of the lack of appropriate application–form instructions for the successor or assignee situation; this has been addressed in the revised application form.

V. Summary of Revisions to Regulation at 37 CFR 202.17

The proposed revision of this regulatory section, 202.17, is extensive and essentially reorders much of the information which previously appeared within this section. The most important change in information concerns the end of the 28th–year renewal registration possibility.

1. Section 202.17(a) more specifically explains the relevant statutory changes of 1992 regarding renewal rights and sets out the distinction between pre–1964 works and post–1964 works with respect to renewal registration.

2. Section 202.17(b) expands the list of terms defined to include ''statutory claimant,'' ''assignee and successor,'' and ''vest'' as those terms relate specifically to the provisions of this renewal registration regulation.

3. Section 202.17(c) explains the relevant time periods for both original term registration and renewal term registration and their optional character as they are set out in the 1992 revision of section 304(a) of Title 17.

4. Section 202.17(d) explains the benefits of 28th–year renewal registration under the 1992 revision to section 304(a) of Title 17 and indicates that such benefits have no longer been available since January 1, 2006, because the regime of 28th–year renewal registration has ended.

5. Section 202.17(e) sets out the parties entitled to the renewal right under 17 U.S.C. 304(a)(1)(B) and (C). This section also:

a. clarifies that, in any derivative work which may be the subject of a renewal application, a renewal claim may be filed only in the new matter, revisions, or changes incorporated into that derivative work and which form the basis of the protected authorship for purposes of registration.

b. clarifies that renewal claims for a work may, under certain circumstances, be filed under the posthumous work category and also under an individual claimant category but with the Copyright Office's taking no position as to which of such claims may be adjudicated to be valid.

For purposes of the copyright statute's renewal provision, the term ''posthumous work'' means a work concerning which no copyright assignment or other contract for exploitation of the work has occurred during the author's lifetime and which is unpublished at the time of the author's death. *Compendium of Copyright Office Practices, Compendium II* (1984), 1317.03(a), citing Bartok v. Boosey & Hawkes, Inc., 523 F.2d 941 (2d Cir. 1975), and H.R. Rep. No. 1476, 94th Cong., 2d Sess 139 (1976). Two parties claiming renewal copyright who take different positions as to whether a particular work falls under the specific definition of ''posthumous'' which Congress adopted from *Bartok* may, thus, file separate and competing claims in such a situation.

c. explains several situations concerning the filing of a renewal registration claim where an executor or a party appointed to fulfill such duties may be the appropriate filer of a renewal claim or where conflicting claims between an administrator of a will and the author's next of kin may be accepted by the Copyright Office.

The Office has also added a phrase, for purposes of § 202.17(e)(2)(iii)(C), qualifying that an executor appointed under a will must still be acting in that capacity at the time of registration when a renewal claim is filed. The phrase ''if still acting in that capacity at the time of registration'' is added to help claimants make decisions concerning their renewal submissions where an executor of a will may or may not be able to act in the filing of a renewal claim. For the uncertainties and varying situations concerning the presence or absence of an executor or administrator and the possibility of the next of kin's claiming as an appropriate section 304 statutory class, *see e.g. Silverman v. Sunrise Pictures Corp.,* 290 F. 804 (2d Cir.), *cert. denied*, 262 U.S. 758 (1923); *Gibran v. Alfred A. Knopf, Inc.*, 153 F. Supp. 854 (S.D.N.Y. 1957), *aff'd sub. nom. Gibran v. National Committee of Gibran*, 255 F.2d 121 (2d Cir.), *cert. denied*, 358 U.S. 828 (1958); *Capano Music v. Myers Music, Inc.*, 605 F. Supp. 692 (S.D.N.Y. 1985).

6. Section 202.17(f) clarifies the situations in which successors and assignees of the section 304(a)(1)(B) and (C) statutory renewal claimants may file applications for renewal registration.

7. Section 202.17(g) indicates the information necessary on a renewal application form for a work for which a previous, original–term registration has been made.

8. Section 202.17(h) indicates the information necessary on a renewal application form and the required accompanying deposit materials in situations for works where no original–term registration has been made. Concerning the Form RE/Addendum to be used in this situation of no original–term registration, regulatory § 202.17(h)(3)(vii) explains that the applicant must provide within the application an averment that all authorized copies of the work which were publicly distributed in the United States or elsewhere before March 1, 1989, carried a statutorily correct copyright notice.

March 1, 1989, is the effective date of the Berne Convention Implementation Act of 1988 [BCIA], making the presence of a copyright notice on copies of a

work, published in the U.S., with the authorization of the copyright owner, optional. Before March 1, 1989, however, any copy, including any reprint copy, of a work published in this country or elsewhere, even though such work may have been first published under the 1909 Copyright Act, must have carried a statutorily required copyright notice. *See* 17 U.S.C. 405.

List of Subjects in 37 CFR Part 202

Claims to copyright, Copyright, Registration requirements, Renewals

Proposed Regulations

In consideration of the foregoing, the Copyright Office proposes to amend Part 202 of 37 CFR, Chapter II, in the manner set forth below:

1. The authority citation for part 202 continues to read as follows:

Authority: 17 U.S.C. 408(f), 702.

2. Section 202.17 is revised to read as follows:

§ 202.17 Renewals

(a) General.

(1) This section concerns renewal for copyrights originally secured from January 1, 1964, through December 31, 1977, either by publication with the required copyright notice or by registration as an unpublished work. Renewal registration for these works is optional.

As provided in Pub. L. No. 102–307, 106 Stat. 264, enacted June 26, 1992, renewal registration made during the last year of the original 28–year term of copyright differs in legal effect from renewal registration made during the 67–year extended renewal term. In the latter instance, the copyright is renewed automatically at the expiration of the original 28–year term.

In the former instance, renewal by registration during the last year of the original 28–year term vested the renewal copyright in the statutory claimant living on the date of registration.

(2) Works for which copyright was secured before 1964 are governed by the provisions of 17 U.S.C. 304(a) in effect prior to the 1992 date of enactment of Pub. L. No. 102–307. The copyrights in such works could have been renewed by registration only within the last calendar year of the original 28–year term of copyright protection. If renewal registration was not made during that period of time, copyright protection was lost when the original term of copyright expired and cannot be regained.

(3) Works restored to copyright by the Uruguay Round Agreements Act are governed in their copyright term of protection by Pub. L. No. 103–465, 108 Stat. 4809, 4976 (December 8, 1994). Under 17 U.S.C. 104A(a)(1)(A) and (B), as amended, any work in which copyright is restored subsists for the remainder of the term of copyright that the work would have been otherwise granted in the United States. Such term includes the remainder of any applicable renewal term.

(4) Automatic restoration of copyright in certain foreign works that were in the public domain in the United States may have occurred under the Uruguay Round Agreements Act and may be protected by copyright or neighboring rights in their ''source country,'' as defined at 17 U.S.C. 104A(h)(8).

(b) Definitions.

(1) For purposes of this section, the terms *assignee* and *successor*, as they pertain to 17 U.S.C. 304(a)(3)(A)(ii), refer to a party which has acquired the renewal copyright in a work by assignment or by other means of legal succession from the statutory claimant [as that claimant is defined in 17 U.S.C. 304(a)(1)(B) and (C)] in whom the renewal copyright vested but in whose name no renewal registration was previously made.

(2) For purposes of this section, a work has been *copyrighted* when it has been published with a proper copyright notice or, in the case of an unpublished work, when it has been registered for copyright.

(3) For purposes of this section, the term *posthumous work* means a work that was unpublished on the date of the death of the author and with respect to which no copyright assignment or other contract for exploitation of the work occurred during the author's lifetime.

(4) For purposes of this section, the term *statutory claimant* means:

(i) a party who was entitled to claim copyright for the renewal term at the time renewal registration was made either as a proprietary claimant ,17 U.S.C. 304(a)(2)(A)(i), or as a personal claimant, 17 U.S.C. 304(a)(2)(B)(i), if registration was made during the original term of copyright; or,

(ii) if the original copyright term expired, a party who was entitled to claim copyright for the renewal term as of the last day of the original term of copyright as either a proprietary or a personal claimant, 17 U.S.C. 304(a)(2)(A)(ii) and (a)(2)(B)(ii).

(5) For purposes of this section, the term to *vest* means to give a fixed, non–contingent right of present or future enjoyment of the renewal copyright in a work. If renewal registration was made during the 28th year of the original term of copyright, the renewal copyright vested in the party or parties entitled to claim such copyright at the time of registration as provided by 17 U.S.C. 304(a)(1)(B) and (C). Although the vested right may have been determined by registration during the 28th year of the original term, the exercise of such right did not commence until the beginning of the renewal term, as provided in 17 U.S.C. 304(a)(2). If renewal registration was not made during the 28th year, the renewal copyright automatically vested upon the beginning of the renewal term in the party or parties entitled to claim such copyright on the last day of the original term as provided by 17 U.S.C. 304(a)(2)(A)(ii) and (B)(ii).

(c) *Time limits: original term and renewal term registration.*

(1) Under 17 U.S.C. 304(a), prior to its amendment of June 26, 1992, a registration for the original term of copyright must have been made during the 28 years of that original term, and a renewal registration must also have been made during the 28th year of that term. Pub. L. No. 102–307, 106 Stat. 264 (June 26, 1992) amended section 304(a) for works originally copyrighted from January 1, 1964, through December 31, 1977, and provided for optional original–term registration and optional renewal registration. 17 U.S.C. 304(a)(2), (a)(3) and 409(11). For such works, claims to renewal copyright could have been registered during the last year of the original term but such registration was not required in order to enjoy statutory protection during the renewal term. 17 U.S.C. 304(a)(3)(B).

(2) A renewal registration can be made at any time during the renewal term. 17 U.S.C. 304(a)(3)(A)(ii). If no original–term registration was made, renewal registration remains possible; but the Register may request information, under 17 U.S.C. 409(11), regarding the original term of copyright. Such information must demonstrate that the work complies with all requirements of the 1909 Act with respect to the existence, ownership, or duration of the copyright for the original term of the work. The Form RE/Addendum is used to provide this information.

(3) Renewal registration is currently available for works copyrighted from January 1, 1964, through December 31, 1977. Under the provisions of 17 U.S.C. 304(a)(3)(A)(ii), renewal registration may be made any time during the 67–year renewal term for such works according to the procedure indicated in paragraph (h) of this section. Such renewal registration is optional and is not a condition of the subsistence of the copyright for the 67–year renewal term. 17 U.S.C. 304(a)(3)(B). In the case of such works for which no registration was made during the original term of

copyright, renewal registration may be made by submission of a Form RE/Addendum. The Addendum, an adjunct to the renewal form, concerns the facts of first publication for a work and assures the Copyright Office that the work as it existed in its original term of copyright was in compliance with the 1909 copyright law, 17 U.S.C. 1, et. seq. (1909 Act, in effect through December 31, 1977), whose provisions govern such works.

(d) *Benefits of 28th–year renewal registration.*

Prior to January 1, 2006, renewal registration was available during the 28th year of the original term of copyright for works copyrighted from January 1, 1964, through December 31, 1977. As provided in Pub. L. No. 102–307, 106 Stat. 264, registration made during the 28th year of the original term of copyright provided the following benefits to the registrant:

(1) The certificate of registration constituted prima facie evidence as to the validity of the copyright during its renewal term and of the facts stated in the certificate. 17 U.S.C. 304(a)(4)(B).

(2) A derivative work prepared under the authority of a grant of a transfer or license of copyright in a work made before the expiration of the original term of copyright could not continue to be used under the terms of the grant during the renewal term without the authority of the owner of the renewal copyright. 17 U.S.C. 304(a)(4)(A).

(3) The renewal copyright vested upon the beginning of the renewal term in the party entitled to claim the renewal of copyright at the time the application was made as provided under 17 U.S.C. 304(a)(2)(A)(i) and (B)(i).

(e) *Statutory parties entitled to claim copyright for the renewal term under section 304(a).*

(1) Renewal claims must be registered in the name of the party or parties entitled to claim copyright for the renewal term as provided in paragraphs 2 through 4 of this section and as specified in 17 U.S.C. 304(a). If a work was a new version of a previously published or registered work, renewal registration may be claimed only in the new matter.

(2) If the renewal claim was submitted during the last, *i.e.*, the 28th, year of the original term of copyright, the claim had to be registered in the name[s] of the statutory claimant[s] entitled to claim the renewal copyright on the date on which the claim was submitted to the Copyright Office. If the renewal claim is submitted during the sixty–seven year extended renewal term, the renewal claim can be registered only in the name[s] of the statutory claimant[s] entitled to claim the renewal on the last day (December 31) of the original term of copyright. These eligible renewal claimants are listed below:

(i) The person who, on the applicable day, was the copyright proprietor is the appropriate renewal claimant in any posthumous work or any periodical, encyclopedia, or other composite work upon which the copyright was originally secured by the proprietor

(ii) The person who, on the applicable day, was the copyright proprietor is the appropriate claimant in any work copyrighted by a corporate body (otherwise than as assignees or licensees of the individual author), or by an employer for whom such work was made for hire.

(iii) For any other copyrighted work, including a contribution by an individual author to a periodical or to an cyclopedic or other composite work, the appropriate claimants, in descending order of eligibility, are the person who, on the applicable day, was:

(A) the author(s) of the work, if still living;

(B) the widow(er) and/or child(ren) of the author, if the author was deceased on the applicable day;

(C) the author's executor(s), if still acting in that capacity on the applicable day, provided the author had a will and neither the author, nor any widow(er) or child of the author is still living;

(D) the author's next of kin, in the absence of a will and if neither the author nor any widow, widower or child of the author is living.

(3) The provisions of paragraphs (e)(1) and (2) of this section are subject to the following qualification: Notwithstanding the definition of ''posthumous work'' in paragraph (b)(4) of this section, a renewal claim may be registered in the name of the proprietor of a work, as well as in the name of the appropriate claimant under paragraph (e)(2)(iii) of this section, in any case in which a contract for exploitation of the work but no copyright assignment in the work has occurred during the author's lifetime. However, registration by the Copyright Office in this case should not be interpreted as evidencing the validity of either claim.

(4) The provisions of paragraphs (e)(2)(iii)(C) and (D) of this section are subject to the following qualifications:

(i) In any case where:

(A) the author has left a will which names no executor; or,

(B) the author has left a will which names an executor who cannot or will not serve in that capacity; or,

(C) the author has left a will which names an executor who has been discharged upon settlement of the estate, removed before the estate has been completely administered, or is deceased at the time of the renewal registration submission, the renewal claim may be registered either in the name of an administrator cum testamento annexo (administrator c.t.a.) or an administrator de bonis non cum testamento annexo (administrator d.b.n.c.t.a.) so appointed by a court of competent jurisdiction.

(ii) In any case described in paragraph (e) of this section, except in the case where the author has left a will without naming an executor and a court–appointed administrator c.t.a. or administrator d.b.n.c.t.a. is in existence at the time of renewal registration, the renewal claim also may be registered in the name of the author's next of kin. However, registration by the Copyright Office of conflicting renewal claims in such a case should not be interpreted as evidencing the validity of either claim.

(f) *Successors/assignees entitled to file an application for the renewal term under section 304(a).*(1) The provisions of paragraph (e) of this section are subject to the following qualifications:

(i) Where no renewal registration has been made in the name of a person or entity identified in paragraphs (e)(2)(i), (ii) and (iii) of this section, a renewal application may be filed at any time during the renewal term by any successor or assignee of such person or entity.

(ii) In such cases described in paragraph (f)(1)(i) of this section, the renewal application must identify the party in whom the renewal copyright vested; must indicate the basis upon which copyright for the renewal term vested in that party; must identify the party who is the successor or assignee of the statutory claimant under 17 U.S.C. 304(a)(3); and, must give the manner by which such successor/assignee secured the renewal copyright.

(iii) When such a claim has been filed by a successor or assignee in the name of the statutory claimant as described in paragraph (e)(2)(i), (ii) and (iii) of this section, generally no subsequent claims may be filed by other successors or assignees whose rights are derived from the same statutory claimant. If a public record of renewal ownership is sought by other successors or assignees of the same statutory claimant, the document of transfer of the renewal copyright, either the renewal in its entirety or in part, may be recorded in the Copyright Office.

(iv) Where a successor or assignee claims the renewal right from the same statutory claimant as does another successor or assignee, the Copyright

Office may inquire concerning the situation and, if appropriate, may allow adverse renewal claims from the successors/assignees to be placed on the public record. In such cases, correspondence between the parties filing competing renewal claims and the Copyright Office will be, as always, maintained within Office records and subject to public inspection according to regulations found at 37 CFR 201.2.

(g) *Application for renewal registration for a work registered in its original 28–year term.*

(1) Each application for renewal registration shall be submitted on Form RE. All forms are available free of charge via the Internet by accessing the Copyright Office homepage at http://www.copyright.gov. Copies of Form RE are also available free upon request to the Public Information Office, United States Copyright Office, Library of Congress, 101 Independence Avenue, Washington, DC 20559–6000.

(2) (i) An application for renewal registration may be submitted by any eligible statutory renewal claimant as specified in paragraph (e) of this section or by the duly authorized agent of such claimant, or by the successor or assignee of such claimant as provided under paragraph (f) of this section or by the duly authorized agent of such successor or assignee.

(ii) An application for renewal registration shall be accompanied by the required fee as set forth in 37 CFR 201.3. The application shall contain the information required by the form and its accompanying instructions, and shall include a certification. The certification shall consist of:

(A) A designation of whether the applicant is the renewal claimant, or a successor or assignee, or the duly authorized agent of such claimant or of such successor or assignee (whose identity shall also be given);

(B) The handwritten signature of such claimant, successor or assignee, or agent, accompanied by the typewritten or printed name of that person;

(C) A declaration that the statements made in the application are correct to the best of that person's knowledge; and

(D) The date of certification.

(3) Once a renewal registration has been made, the Copyright Office will not accept another application for renewal registration on behalf of the same renewal claimant.

(h) *Renewal with addendum registration for an unregistered work.*

(1) *General.* For published works copyrighted from January 1, 1964, through December 31, 1977, where no registration was made during the original term of copyright and where renewal registration is sought during the 67–year renewal term, the Form RE/Addendum must be used to provide information concerning the original term of copyright. The Form RE/Addendum requires a separate fee and the deposit of one copy or phonorecord of the work as first published (or identifying material in lieu of a copy or phonorecord). The effective date of registration for a renewal claim submitted on a Form RE/Addendum is the date the Copyright Office receives an acceptable completed application, the required fees, and an acceptable deposit for the work.

(2) *Time Limits.* A renewal claim accompanied by an Addendum to Form RE may be filed at any time during the 67–year renewal term.

(3) *Content.* The Form RE/Addendum must contain the following information:

(i) The title of the work;

(ii) The name of the author(s);

(iii) The date of first publication of the work;

(iv) The nation of first publication of the work;

(v) The citizenship of the author(s) on the date of first publication of the work;

(vi) The domicile of the author(s) on the date of first publication of the work;

(vii) An averment that, at the time of first publication, and thereafter until March 1, 1989 [effective date of the Berne Implementation Act of 1988], all the copies or phonorecords of the work, including reprints of the work, published, *i.e.*, publicly distributed in the United States or elsewhere, under the authority of the author or other copyright proprietor, bore the copyright notice required by the Copyright Act of 1909 and that United States copyright subsists in the work;

(viii) For works of United States origin which were subject to the manufacturing provisions of section 16 of the Copyright Act of 1909 as it existed at the time the work was published, the Form RE/Addendum must also contain information about the country of manufacture and the manufacturing processes; and

(ix) The handwritten signature of the renewal claimant or successor or assignee, or the duly authorized agent of the claimant or of the successor or assignee. The signature shall be accompanied by the printed or typewritten name of the person signing the Addendum and by the date of the signature; and shall be immediately preceded by a declaration that the statements made in the application are correct to the best of that person's knowledge.

(4) *Fees.* Form RE and Form RE/Addendum must be accompanied by the required fee for each form as required in 37 CFR 201.3.

(5) *Deposit requirement.* One copy or phonorecord or identifying material of the work as first published in accordance with the deposit requirements set out in 37 CFR 202.20 and 202.21 is required.

(6) *Waiver of the deposit requirement.* Where the renewal applicant asserts that it is either impossible or otherwise an undue hardship to satisfy the deposit requirements of 37 CFR 202.20 and 202.21, the Copyright Office, at its discretion, may, upon receipt of an acceptable explanation of the inability to submit such copy or identifying material, permit the deposit of the following in descending order of preference. In every case, however, proof of the copyright notice showing the content and location of the notice as it appeared on copies or phonorecords of the work as first published must be included.

(i) A reproduction of the entire work as first published (*e.g.*, photocopy, videotape, audiotape, CD–ROM, DVD are examples of physical media which may hold reproductions of a work as first published). If the work is a contribution to a periodical, a reproduction of only the contribution (including the relevant copyright notice) will suffice.

(ii) A reprint of the work (*e.g.*, a later edition, a later release of a phonorecord, or the like). The reprint must show the copyright notice as it appeared in the same location within the first published copy of the work as well as the exact content of the copyright notice appearing in the first published edition. If the copyrightable content of the reprint differs from that of the first published edition, an explanation of the differences between the two editions is required.

(iii) Identifying material including a reproduction of the greatest feasible portion of the copyrightable content of a work including a photocopy or photograph of the title page, title screen, record label or the like, as first published, and a photocopy or photograph showing the copyright notice content and location as first published. The Copyright Office may request deposit of additional material if the initial submission is inadequate for examination purposes.

Dated: March 28, 2007.

Marybeth Peters,

Register of Copyrights.

[FR Doc. E7–6174 Filed 4–3–07; 8:45 am]

BILLING CODE 1410–30–S

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 152, 156, 167, 168, 169, 172, and 174

[EPA–HQ–OPP–2006–1003; FRL–8118–2]

RIN 2070–AJ32

Plant-Incorporated Protectants; Potential Revisions to Current Production Regulations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Advance Notice of Proposed Rulemaking (ANPRM).

SUMMARY: In light of the differences between plant-incorporated protectants (PIPs) and other types of pesticides, EPA is considering amendments to the current pesticide establishment and production regulations promulgated under the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), and to other related FIFRA regulations as needed for producers of PIPs. PIPs are pesticidal substances that are intended to be produced and used in a living plant, or the produce thereof, and the genetic material necessary for the production of such a pesticidal substance, and also include any inert ingredient contained in the plant, or the produce thereof. Given these characteristics, it is possible that PIPs may not be produced in the manner contemplated when the current establishment and production regulations were promulgated for other types of pesticide. In this ANPRM, the Agency provides a list of the general regulatory provisions applicable to PIPs that EPA is considering amending and solicits public comment on the completeness of the list and the scope of any potential changes to these regulations. EPA also is soliciting information that may be useful to EPA as it reviews these regulations and developing the proposed rules. In addition to soliciting comments through this ANPRM, EPA intends to solicit stakeholder input through two public meetings during the comment period of this ANPRM.

DATES: Comments must be received on or before June 13, 2007.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPP–2006–1003, by one of the following methods:

• *Federal eRulemaking Portal*: *http://www.regulations.gov*. Follow the on-line instructions for submitting comments.

• *Mail*: Office of Pesticide Programs (OPP) Regulatory Public Docket (7502P), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001.

• *Delivery*: OPP Regulatory Public Docket (7502P), Environmental Protection Agency, Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. Deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays). Special arrangements should be made for deliveries of boxed information. The Docket Facility telephone number is (703) 305–5805.

Instructions: Direct your comments to docket ID number EPA–HQ–OPP–2006–1003. EPA's policy is that all comments received will be included in the docket without change and may be made available on-line at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through regulations.gov or e-mail. The regulations.gov website is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through regulations.gov, your e-mail address will be automatically captured and included as part of the comment that is placed in the docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the docket index available in regulations.gov. To access the electronic docket, go to *http://www.regulations.gov*, select ''Advanced Search,'' then ''Docket Search.'' Insert the docket ID number where indicated and select the ''Submit'' button. Follow the instructions on the regulations.gov web site to view the docket index or access available documents. Although listed in the index, some information is not publicly available, e.g., 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 either in the electronic docket at *http://www.regulations.gov*, or, if only available in hard copy, at the OPP Regulatory Public Docket in Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. The hours of operation of this Docket Facility are from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The Docket Facility telephone number is (703) 305–5805.

FOR FURTHER INFORMATION CONTACT: Stephen Howie, Hazard Assessment Coordination and Policy Division (7202M), Office of Science Coordination and Policy, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: (202) 564–4146; fax number: (202) 564–8502; e-mail address: *howie.stephen@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

You may be potentially affected by this action if you manufacture, import, process, or use PIPs. In order to identify potentially impacted industries the analysis relies on North American Industrial Classification System (NAICS) codes. Potentially affected entities may include, but are not limited to:

• Pesticide and Other Agricultural Chemical Manufacturing (NAICS code 325320). This industry comprises establishments that are producing PIPs intended for distribution and sale as pesticides.

• Crop Production (NAICS code 111). These are establishments such as farms, orchards, groves, greenhouses, and nurseries, primarily engaged in growing crops, plants, vines, or trees and their seeds.

• Colleges, Universities, and Professional Schools (NAICS code 611310). This industry comprises establishments primarily engaged in furnishing academic courses and granting degrees at baccalaureate or graduate levels. Furthermore, they may comprise establishments where research on PIPs occurs and where PIPs may be grown.

• Research and Development in the Physical, Engineering, and Life Sciences (NAICS code 54171). This industry comprises establishments primarily engaged in conducting research and experimental development in the physical, engineering, or life sciences, such as agriculture, environmental,

biology, botany, biotechnology, forests, and other allied subjects.

This listing is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in this unit could also be affected. The North American Industrial Classification System (NAICS) codes have been provided to assist you and others in determining whether this action might apply to certain entities. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed under **FOR FURTHER INFORMATION CONTACT**.

B. What Should I Consider as I Prepare My Comments for EPA?

1. *Docket.* EPA has established a docket for this action under docket ID number EPA–HQ–OPP–2006–1003. Publicly available docket materials are available either in the electronic docket at *http://www.regulations.gov*, or, if only available in hard copy, at the Office of Pesticide Programs (OPP) Regulatory Public Docket in Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. The hours of operation of this Docket Facility are from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The Docket Facility telephone number is (703) 305–5805.

2. *Tips for preparing your comments.* When submitting comments, remember to:

i. Identify the document by docket ID number and other identifying information (subject heading, **Federal Register** date and page number).

ii. Follow directions. The Agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

iii. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

iv. Describe any assumptions and provide any technical information and/or data that you used.

v. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

vi. Provide specific examples to illustrate your concerns and suggest alternatives.

vii. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

viii. Make sure to submit your comments by the comment period deadline identified.

II. Background

A. What Action is the Agency Taking?

PIPs are ''pesticidal substances that are intended to be produced and used in a living plant, or the produce thereof, and the genetic material necessary for the production of such a pesticidal substance. PIPs also include any inert ingredient contained in the plant, or the produce thereof.'' (40 CFR 174.3) By definition, PIPs are primarily distinguished from other types of pesticides because they are intended to be produced and used in the living plant. Other types of pesticides are primarily produced in a facility and used through physical application, e.g., spraying or dusting of the plant. Since PIPs were not defined when the existing regulations associated with pesticide establishments and pesticide production were promulgated, the existing regulations may not adequately address this distinction.

The Agency is therefore considering amending the current FIFRA regulations associated with pesticide establishments and pesticide production to better address PIPs and PIP production given the unique characteristics of PIPs compared to other types of pesticides.

EPA is soliciting comments from interested stakeholders on the issues and questions identified in this ANPRM. EPA intends to use this information in reviewing these regulations and developing its proposed rules.

B. What is the Agency's Authority for Taking this Action?

EPA has regulatory authority to promulgate regulations under FIFRA sections 3(a), 8(a), 25(a), and 25(b) (7 U.S.C. 136a(a), 136f(a), 136w(a), and 136w(b)).

PIPs are pesticides under FIFRA section 2 because they are introduced into plants with the intention of ''preventing, destroying, repelling, or mitigating any pest...'' (7 U.S.C. 136(u)).

Under FIFRA section 7, any person who manufactures, prepares, compounds, propagates, or processes any pesticide is a ''producer.'' ''Produce,'' as further described in in 40 CFR 167.3, also means to package, repackage, label, relabel, or otherwise change the container of any pesticide. FIFRA section 7 requires that producers of pesticides register the establishments where production occurs and requires that producers report their annual production (7 U. S. C. 136e). In addition, producers of pesticides are required under FIFRA section 8(a) to maintain records with respect to their operations, and to make such records available for inspection (7 U.S.C. 136f(a)). Under FIFRA section 9 appropriately credentialed inspectors have the authority to conduct inspections at pesticide producing establishments or other places where pesticides are being held for distribution or sale for the purpose of inspecting and obtaining samples (7 U.S.C. 136g).

C. Why is the Agency Considering Amending the Regulations?

EPA believes that the existing regulations need to be amended to better address apparent differences between PIPs and other types of pesticides in the application of FIFRA's production and production-related requirements. The existing regulations were written for pesticides that are generally produced and used in a more traditional manner, e.g., spraying or dusting onto the plants. PIPs are produced and used in a living plant, which raises questions regarding how that ''production'' should be regulated under the existing authorities of FIFRA. In general, EPA's experience with PIPs is that they present different and potentially lower risk situations compared to chemical pesticides. However, EPA needs to ensure that appropriate PIP production data are available to manage any potential risk a PIP might pose.

The United States Government published in the **Federal Register** issue of June 26, 1986 (51 FR 23302) a document entitled, *Coordinated Framework for Regulation of Biotechnology* (''Coordinated Framework''), which describes in broad terms the Federal Government's approach to regulating biotechnology products. In that document, the Federal Government concluded that it could appropriately regulate the products of biotechnology under existing laws, but recognized that, in some cases, new regulations might be needed. Consistent with the Coordinated Framework, EPA regulates PIPs under its pesticide authorities. In the **Federal Register** issue of July 19, 2001 (66 FR 37771) (FRL–6057–7), EPA published a rule that established a regulatory framework for PIPs. That rule clarified the relationship between plants and PIPs under FIFRA, exempted from FIFRA requirements PIPs derived entirely through conventional breeding between sexually compatible plants, established a new part in the Code of Federal Regulations specifically for PIPs (40 CFR part 174), provided requirements for reporting of adverse effects, and set forth certain procedures for CBI. In that **Federal Register** document, EPA also anticipated the future need for proposing regulations tailored

specifically to PIPs so that the regulatory framework would better fit their unique characteristics (66 FR 37807). EPA indicated that it would continue to apply existing regulations to PIPs, except where superseded by the regulations in the July 19, 2001 Final Rule, until the Agency could develop additional regulations specifically tailored to PIPs.

Since the mid-1990s, EPA has approved a number of PIP experimental use permits (EUPs) under FIFRA section 5, as well as seed increase and commercial use registrations under FIFRA section 3. During this time, EPA has registered facilities involved in the production of PIPs as pesticide producing establishments under FIFRA section 7. These have included, for example, sites of the original transformation (where plant tissue was transformed by the insertion of PIP genetic material) and seed processing facilities.

FIFRA section 7 requires that producers of pesticides register the establishments where the pesticide is produced and report the amount of pesticide produced. EPA's experience to date has demonstrated, particularly in the area of pesticide production, that the existing regulations (e.g., 40 CFR part 167) may need to be better tailored to address PIPs. For example, existing regulations require pesticide production quantities to be reported in terms of volume or weight (gallons or pounds), measurements that are not useful when considering a pesticidal substance produced within a plant. Other questions concern the manner in which PIPs are increased within a living plant. Such increase occurs at many stages from product development through use, which raises questions concerning where pesticide production occurs, and what establishments must register and report their production. Clarification of this matter would help to ensure that appropriate persons comply with production related requirements, and that other persons do not face unnecessary regulatory burden. To that end, EPA is reviewing the existing regulations in 40 CFR chapter I, subchapter E and considering potential regulatory changes to address the apparent differences between PIPs and other types of pesticides.

III. Current Regulations Under Review

EPA is considering amending the following existing regulations related to pesticide establishment and production to better address PIPs and PIP production:

1. *Registration of establishments where PIPs are produced* (FIFRA section 7 and 40 CFR 167.20). Current regulations require any producer of a pesticide to register the ''production'' site with EPA. The statutory and regulatory definitions of ''produce'' include several activities, including manufacturing, preparing, compounding, propagating, or processing any pesticide or packaging, repackaging, labeling, and relabeling the container of any pesticide.

2. *Reporting by registered production establishments* (FIFRA section 7 and 40 CFR 167.85). Current regulations require a producer operating a producing establishment to report annually the types and amount of each pesticidal product that was produced, sold, or distributed the previous year and to estimate the amount that will be produced during the current year.

3. *Recordkeeping and inspection authority* (FIFRA sections 8 and 9 and 40 CFR 169.2 and 169.3). EPA's statutory authority under FIFRA section 8, and the regulations promulgated thereunder, require pesticide producers, registrants, and applicants for registration to maintain certain records related to pesticide production (i.e., including information regarding the production, receipt, and shipment of pesticides) and to provide these records upon request to appropriately credentialed inspectors. FIFRA section 8 also provides authority for appropriately credentialed inspectors to conduct inspections to access such information. Furthermore, under FIFRA section 9 appropriately credentialed inspectors have the authority to conduct inspections at pesticide producing establishments or other places where pesticides are being held for distribution or sale for the purpose of inspecting and obtaining samples.

4. *Labeling on PIP containers* (FIFRA section 2 and 40 CFR 156.10). The statute and current regulations provide requirements for labeling of pesticides, including name of the product, identity of the producer, net content, product registration number, establishment registration number, ingredient statement, hazard and precautionary statements, directions for use, and use classification. Currently, PIPs are labeled for FIFRA section 5 EUPs and FIFRA section 3 seed increase registrations only.

5. *EUPs for field testing of unregistered PIPs* (FIFRA section 5 and 40 CFR part 172). FIFRA allows for field testing of unregistered pesticides under an EUP. Any pesticide production activity related to an EUP, either the production of a pesticide for use in an EUP or by being produced as a result of an EUP, is subject to FIFRA production establishment and recordkeeping requirements.

6. *Production of unregistered PIPs for export* (FIFRA section 17 and 40 CFR 168.65–168.85). FIFRA exempts pesticides intended solely for export from certain FIFRA requirements, including product registration requirements. Products intended for export only are therefore not subject to the product safety evaluation required of products intended for domestic distribution and sale. However, they must still comply with the producer establishment registration, reporting and recordkeeping requirements of FIFRA sections 7 and 8 and are subject to certain labeling requirements, e.g., their label must include the statement: ''Not Registered for Use in the United States of America.''

IV. Request for Comments

EPA is seeking public comment on the completeness of the list of current regulations that need to be reviewed for applicability to PIPs and PIP producers (see Unit III.), and is soliciting related information to use in reviewing these regulations and developing its proposed rules. These issues are especially challenging for PIPs, since based on statutory and regulatory definitions, the borders between production and use are unclear. EPA is seeking public input to help inform decisions on how best to ensure appropriate compliance without imposing unnecessarily burdensome reporting or labeling requirements on PIP registrants, producers, distributors, and users.

1. EPA would like comments in response to the following questions with respect to the regulations referenced in Unit III.:

a. *Registration of establishments* (Unit III.1.). Given that PIPs by definition are intended to be produced and used in a living plant, what activities should the Agency consider to be part of ''production'' as that term is defined in FIFRA (which includes manufacturing, preparing, compounding, propagating, or processing any pesticide or packaging, repackaging, labeling, and relabeling the container), and what establishments should be registered to help EPA manage any potential risks associated with PIPs? What other types of facilities, if any (e.g., growers involved in seed production), involved in the development of PIP-containing varieties should be subject to these requirements? Please explain the reason for your response.

b. *Production reporting* (Unit III.2.). What production reporting, by whom and in what units (e.g., volume, weight, number of seeds, etc.) would be

appropriate? Should reporting units be dependent on the reproductive methodology of the crop (e.g., seeds, bulbs, or tubers)? Given your response to Unit IV.1.a., what types of production reporting would provide the Agency with information valuable for compliance assurance purposes and for managing any potential risks associated with a violation?

c. *Recordkeeping and inspection* (Unit III.3.). What establishments or other locations are appropriate to be inspected for records and samples, and what records would be appropriate for producers of PIPs to maintain?

d. *Labeling* (Unit III.4.). Please comment on current labeling practices for PIPs. Are current labeling practices sufficient? For example, do grower agreements offer sufficient information and compliance assurance to ensure registered PIPs are used in a manner that protects human health and the environment? Are there circumstances where labeling different from that currently in practice for PIPs may be appropriate?

e. *Experimental use permits* (Unit III.5.). Are there aspects of production in association with PIP EUPs that are different from production associated with other types of pesticides used in EUPs? If there are differences, how should they be addressed for PIP EUPs?

f. *Production for export* (Unit III.6.). What conditions would ensure that a PIP is intended for export only, and what would be necessary for such a PIP to meet the requirements of FIFRA?

2. Are there other characteristics not described in this document unique to PIPs that may affect the application of the existing regulations associated with pesticide establishments and pesticide production to PIP producers?

3. Are there additional sections of FIFRA implementing regulations related to pesticide establishment and production regulations that should be modified to more effectively address the unique characteristics of PIPs?

V. Do Any Statutory or Executive Order Reviews Apply to this Action?

Under Executive Order 12866, entitled *Regulatory Planning and Review* (58 FR 51735, October 4, 1993), the Office of Management and Budget (OMB) has determined that ANPRMs are considered ''significant regulatory actions'' under section 3(f) of the Executive Order. The Agency therefore submitted this document to OMB for the 10–day review period afforded under this Executive order. Any changes made in response to OMB comments during that review have been documented in the docket as required by the Executive order.

Since this ANPRM does not impose or propose any requirements, and instead seeks comments and suggestions for the Agency to consider in possibly developing a subsequent proposed rule, the various other review requirements that apply when an agency imposes requirements do not apply to this action.

As part of your comments on this ANPRM, you may include any comments or information that you have regarding this action. In particular, any comments or information that would help the Agency to assess the potential impact of a rule on small entities pursuant to the Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*); to consider voluntary consensus standards pursuant to section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, section 12(d) (15 U.S.C. 272 note); to consider environmental health or safety effects on children pursuant to Executive Order 13045, entitled *Protection of Children from Environmental Health Risks and Safety Risks* (62 FR 19885, April 23, 1997); or to consider human health or environmental effects on minority or low-income populations pursuant to Executive Order 12898, entitled *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations* (59 FR 7629, February 16, 1994). The Agency will consider such comments during the development of any subsequent notice of proposed rulemaking as it takes appropriate steps to address any applicable requirements.

List of Subjects in 40 CFR Parts 152, 156, 167, 168, 169, 172, 174

Environmental protection, Pesticides and pests, Plant-incorporated protectants, Reporting and recordkeeping requirements.

Dated: March 22, 2007.

Stephen L. Johnson,

Administrator.

[FR Doc. E7–6151 Filed 4–3–07; 8:45 am]

BILLING CODE 6560–50–S

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[DA 07–1350; MB Docket No. 04–319; RM–10984]

Radio Broadcasting Services; Clinchco, VA and Coal Run, KY

AGENCY: Federal Communications Commission.

ACTION: Proposed rule, denial.

SUMMARY: This document denies a petition for rule making filed by East Kentucky Broadcasting Corp. (''Petitioner'') proposing to substitute Channel 221C3 for Channel 276A at Coal Run and modify the license of Station WPKE–FM to reflect the channel upgrade. To accommodate the channel upgrade, Petitioner proposes to substitute Channel 276A for Channel 221A at Clinchco, Virginia and modify the license of Station WDIC–FM to reflect the channel substitution. However, Petitioner's proposed site is unacceptable due to major terrain obstruction that prevents the requisite 70 dBu signal over the entire community of license.

FOR FURTHER INFORMATION CONTACT: Robert Hayne, Media Bureau, (202) 418–2177.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's Report and Order, MB Docket No. 04–319, adopted March 16, 2007, and released March 20, 2007. The full text of this Commission decision is available for inspection and copying during regular business hours at the FCC's Reference Information Center, Portals II, 445 Twelfth Street, SW., Room CY–A257, Washington, DC 20554. The complete text of this decision may also be purchased from the Commission's duplicating contractor, Best Copy and Printing, Inc., 445 12th Street, SW., Room CY–B402, Washington, DC 20554, telephone 1–800–378–3160 or *http://www.BCPIWEB.com.*

This document is not subject to the Congressional Review Act. (The Commission, is, therefore, not required to submit a copy of this Report and Order to the Government Accountability Office pursuant to the Congressional Review Act, *see* 5 U.S.C. 801(a)(1)(A) because the proposed rule is denied.)

Federal Communications Commission.

John A. Karousos,

Assistant Chief, Audio Division, Media Bureau.

[FR Doc. E7–6258 Filed 4–3–07; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

49 CFR Parts 1300 and 1313

[STB Ex Parte No. 669]

Interpretation of the Term ''Contract'' in 49 U.S.C. 10709

AGENCY: Surface Transportation Board, DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Surface Transportation Board seeks public comments on a proposal to interpret the term ''contract'' in 49 U.S.C. 10709 as embracing any bilateral agreement between a carrier and a shipper for rail transportation in which the railroad agrees to a specific rate for a specific period of time in exchange for consideration from the shipper, such as a commitment to tender a specific amount of freight during a specific period or to make specific investments in rail facilities.

DATES: Comments are due by June 4, 2007. Reply comments are due August 2, 2007.

ADDRESSES: Comments may be submitted either via the Board's e-filing format or in the traditional paper format. Any person using e-filing should comply with the instructions at the E-FILING link on the Board's Web site, at *http://www.stb.dot.gov.* Any person submitting a filing in the traditional paper format should send an original and 10 copies to: Surface Transportation Board, Attn: STB Ex Parte No. 669, 395 E Street, SW., Washington, DC 20423–0001.

Copies of written comments will be available from the Board's contractor, ASAP Document Solutions (mailing address: Suite 103, 9332 Annapolis Rd., Lanham, MD 20706; e-mail address: *asapdc@verizon.net*; telephone number: 202–306–4004). The comments will also be available for viewing and self-copying in the Board's Public Docket Room, Room 755, and will be posted to the Board's Web site at *http://www.stb.dot.gov*.

FOR FURTHER INFORMATION CONTACT: Joseph H. Dettmar at 202–245–0395. [Assistance for the hearing impaired is available through the Federal Information Relay Service (FIRS) at 1–800–877–8339.]

SUPPLEMENTARY INFORMATION: Until the late 1970s, the Board's predecessor, the Interstate Commerce Commission (ICC), had found contract rates between a railroad and a shipper to be per se unlawful. They were regarded as a destructive competitive practice that would have the effect of damaging existing rate structures and reducing competition.[1] In 1978, the ICC changed course, issuing a policy statement acknowledging that contract rates may be beneficial in many circumstances because ''a shipper is guaranteed a certain rate for the period of the contract while the carrier knows what service that shipper will receive.'' [2] In that proceeding, the ICC adopted the following definition of a rail ''contract rate'':

> a railroad freight rate arrived at through mutual agreement between a railroad * * * and a shipper in which the railroad agrees to provide service for a given price and the shipper agrees to tender a given amount of freight during a fixed period.[3]

Rather than finding all such agreements lawful, however, the ICC undertook to review the legality of contract rates on a case-by-case basis.

Congress viewed the ICC's changed policy as insufficient, because it had ''a number of restrictions and uncertainties and [had] resulted in the limited use of contracts.'' [4] To ensure that shippers and railroads would be free to enter into rail transportation contracts ''without concern about whether the ICC would disapprove a contract,'' [5] in the Staggers Rail Act of 1980 (Staggers Act),[6] Congress amended the statute to provide that railroads ''may enter into a contract with one or more purchasers of rail services to provide specified services under specified rates and conditions.'' Former 49 U.S.C. 10713(a) (1995) (now codified at 49 U.S.C. 10709(a)). When originally enacted, the provision further stated that ''a rail carrier may not enter into a contract with purchasers of rail service except as provided in this section.'' Former 49 U.S.C. 10713(a) (1995).

Congress also expressly removed all matters and disputes arising from rail transportation contracts from the ICC's (and now the Board's) jurisdiction. See former 49 U.S.C. 10713(i) (1995) (now codified at 49 U.S.C. 10709(c)). If the parties have a dispute regarding such a contract—such as whether there has been adequate performance or whether the contract is void because it was signed under duress—such matters are to be decided by the courts under applicable state contract law. See former 49 U.S.C. 10713(i)(2) (1995) (now codified at 49 U.S.C. 10709(c)(2)). Congress also explained that, if someone believes that a contract is anticompetitive, ''the antitrust laws are the appropriate and only remedy available.'' [7] Congress considered the contract rate provision of the Staggers Act to be ''among the most important in the bill.'' [8] But there is no clear distinction in the statute or our precedent between a contract and a common carrier rate.

In a recent proceeding, *Kansas City Power & Light Company* v. *Union Pacific Railroad Company,* STB Docket No. 42095 (*KCPL*), the Board asked the parties to submit briefs to discuss a hybrid pricing mechanism that the carrier designated a common carrier pricing arrangement, but could be viewed as a rail transportation contract. *See Kansas City Power & Light Co.* v. *Union Pac. R.R.,* STB Docket No. 42095 (STB served July 27, 2006). The parties took the position that the rates at issue were common carrier rates subject to the Board's jurisdiction. The parties cited agency precedent for the proposition that a common carrier rate ''is nothing more than a special kind of contract between a carrier and its shippers,'' citing *National Grain & Feed Assoc.* v. *BN RR. Co., et al.*, 8 I.C.C.2d 421, 437 (1992), and whether a contract or common carrier rate exists has been examined on a case-by-case basis in light of the parties' intent, citing *Aggregate Volume Rate on Coal, Acco, UT to Moapa, NV,* 364 I.C.C. 678, 689 (1981) (Utah). The parties also pointed out that the agency has in the past stated that the purpose of allowing for contract rates is to establish negotiated, mutually agreeable rates to which parties intend to be bound. *See Utah,* 364 I.C.C. at 689; *see also Product and Geographic Competition,* 2 I.C.C.2d 1, 11 (1985); *Market Dominance Determinations,* 365 I.C.C. 118, 125 (1981). The Union Pacific Railroad Company (UP) also argued that it can enter into any kind of bilateral agreement with a shipper, but maintain Board jurisdiction by labeling the agreement a common carrier rate rather than a contract rate. It contended that a carrier has the authority to designate what type of rate it is establishing, based on section 10701(c),

[1] *See Contract Rates on Rugs and Carpeting from Amsterdam, N.Y., to Chicago*, 313 I.C.C. 247, 254 (1961); *Guaranteed Rates from Sault Ste. Marie, Ontario, Canada, to Chicago*, 315 I.C.C. 311, 323 (1961).

[2] *Change of Policy Railroad Contract Rates,* Ex Parte No. 358–F (ICC served Nov. 9, 1978).

[3] *See* former 49 CFR 1039.1 (1979).

[4] H.R. Rep. No. 96–1035, 96th Cong., 2nd Sess. (May 16, 1980) at 57 (*House Report*); *see also* S. Rep. No. 96–470, 96th Cong., 1st Sess. (Dec. 7, 1979) at 24 (*Senate Report*) (the changes are ''intended to clarify the status of contract rate and service agreements in an effort to encourage carriers and purchasers of rail service to make widespread use of such agreements'').

[5] *House Report* at 58; *see also Senate Report* at 24.

[6] Pub. L. No. 96–448, 94 Stat. 1895 (1980).

[7] *House Report* at 58.

[8] *Senate Report* at 9.

arguing ''[u]nless a specific prohibition applies, 'a rail carrier may establish any rate for transportation or other service provided by the rail carrier.' Rail carriers thus have broad flexibility to design common carrier offerings as alternatives to rail transportation contracts in response to business needs.'' [9] Because the parties could have reasonably relied on prior agency precedent to conclude that this kind of hybrid pricing mechanism is subject to Board jurisdiction, we concluded that it would be inappropriate to set aside or reexamine that ICC precedent in that adjudication.

Nevertheless, we have serious concerns about the lack of any clear demarcation between contract and common carrier rates because of the boundaries on our jurisdiction. The carrier in the *KCPL* proceeding has crafted a hybrid pricing mechanism that appears to have all of the characteristics of a rail transportation contract, but avoids some important consequences of entering into such a contract by its choice of label. Traditionally, common carrier pricing has been a holding out to the public to provide a specified transportation services for a given price that a shipper accepts by tendering traffic. Under these unilateral contracts,[10] the carrier has the right to change the common carrier rates or terms upon 20 days' notice under 49 U.S.C. 11101(c). In other words, where there is no mutuality of consideration, a carrier can unilaterally withdraw one offer and replace it with another.

The new pricing structures we are witnessing as reflected in the *KCPL* proceeding, however, contain a mutuality of obligation between the carriers and shippers that appear to have the hallmarks of a contractual relationship. These bilateral agreements mutually bind both the shipper and the carrier for a given period of time. In exchange for some sort of consideration from the shipper, the carrier commits to a specific rate or service for a specific term. While Congress intended to permit carriers to have the pricing flexibility to enter into these kinds of agreements, we believe that Congress also intended for these contractual agreements to be confidential, outside Board jurisdiction, and subject to the scrutiny of the antitrust laws, rather than regulation under the Interstate Commerce Act.

We also have concerns that the increased used of these hybrid pricing mechanisms could create an environment where collusive activities in the form of anticompetitive price signaling could occur. Whereas the terms and conditions of common carrier rates must be publicly disclosed under section 11101,[11] the terms of a rail transportation contract are to be kept confidential, a factor that makes collusion in this highly concentrated industry more difficult.[12] Thus, a carrier's hybrid pricing mechanism may not contain the same protections against collusion as do traditional confidential transportation contracts. An important competitive benefit of contracts is that they often enable shippers to obtain service commitments and lower rates that carriers might not otherwise offer through the public tariff process.

We also question whether the position advanced by UP that these sorts of rates are authorized by section 10701(c) is consistent with the statutory scheme. Read in context with the other provisions of section 10701, we believe that subsection (c) addresses the *level* of the rate that a carrier may set in the first instance, and does not allow the carrier to control the designation of the type of rate that is involved. Moreover, under the railroad's interpretation, there would appear to be no type of agreement between a carrier and a shipper—no matter how long the term or how individually tailored or bilateral the responsibilities created—that a carrier could not unilaterally label common carrier rate and service terms. If that were so, the contract provision in section 10709 would become largely superfluous.

Similarly, the carrier's interpretation would render section 10722 redundant. In that provision, Congress expressly authorized rail carriers to establish premium charges in common carrier rates for special services or special levels of service in order to encourage more efficient use of freight cars. *See* 49 U.S.C. 10722. If, however, section 10701 authorizes common carrier tariffs that embrace any kind of special rates and terms, it would not have been necessary for Congress to separately authorize special rates in section 10722.

We are inclined to find that a more reasonable interpretation of the statute is that section 10701 does not authorize carriers to enter into either special common carrier rates or bilateral contractual agreements. Both the authority for, and limitations on, those types of rates are set forth in sections 10722 and 10709, respectively. Section 10709, in turn, removes those contracts from the regulatory scheme associated with common carrier service.

In light of the above concerns, we seek public comment on our proposed interpretation of the term ''contract'' in section 10709 as embracing any bilateral agreement between a carrier and a shipper for rail transportation in which the railroad agrees to a specific rate for a specific period of time in exchange for consideration from the shipper, such as a commitment to tender a specific amount of freight during a specific period or to make specific investments in rail facilities. Under the proposed interpretation, notwithstanding any carrier representation that the rate specified in the agreement is a common carrier rate, such a bilateral agreement would be regarded by the Board as a rail transportation contract under section 10709 and therefore outside the Board's jurisdiction. *See Columbia Gas Transmission Corp.* v. *FERC,* 404 F.3d 459, 463 (D.C. Cir. 2005) (''jurisdiction cannot arise from the absence of objection, or even from affirmative agreement. To the contrary, as a statutory entity, [the agency] cannot acquire jurisdiction merely by agreement of the parties before it.''); *see also Weinberger* v. *Bentex Pharms., Inc.,* 412 U.S. 645, 652 (1973) (only Congress, not parties, may confer jurisdiction).

Though we need not seek public comments before issuing an interpretative rule of this nature, we do so here to ensure that we have fully considered the issues and ramifications before taking this action. We do not intend to stifle innovation in transportation markets or otherwise disadvantage any party.

To the extent this interpretation could be seen as contradicting past agency statements regarding whether a bilateral agreement can constitute a common carrier rate, we would apply this

[9] *See* STB Docket No. 42095, UP's Response to Order to Show Cause, at 8 (filed Sept. 25, 2006).

[10] A unilateral contract is one in which one party makes an express engagement or undertakes a performance, without receiving in return any express engagement or promise of performance from the other. The essence of a unilateral contract is that neither party is bound until the promisee accepts the offer by performing the proposed act. Black's Law Dictionary 277 (6th abr. Ed. 1991).

[11] *See* 49 CFR 1300.2 (''A rail carrier must disclose to any person, upon formal request, the specific rates(s) requested * * *. as well as all charges and service terms * * *.'').

[12] *See, e.g., Canadian National, et al.—Control—Illinois Central, et al.,* 4 S.T.B. 122, 149 (1999) (''As we explained in the *UP/SP* decision affirmed by the court, there are three elements, all of which are present here, that each make tacit collusion unlikely for markets in which two railroads operate. First, tacit collusion cannot flourish where, as in railroading, rate concessions can and are made secretly through confidential contracts.''); *see also Water Transport Ass'n* v. *ICC,* 722 F.2d 1025 (2d Cir. 1983) (''[I]t has long been recognized under the antitrust laws that public disclosure of contract terms can undermine competition by stabilizing prices at an artificially high level.''); *see generally Petition To Disclose Long-Term Rail Coal Contracts,* ICC Ex Parte No. 387 (Sub-No. 961) (ICC served July 29, 1988) (lengthy discussion of the confidentiality of rail transportation contracts).

interpretation prospectively only. However, we do not want to create incentives for a carrier to rush to put into place as many rates as possible in hybrid ''common carrier'' agreements during the period of unavoidable delay associated with seeking public comments. Therefore, should we adopt this interpretative rule, we intend to apply the rule to all agreements entered into after the date of publication of this decision in the **Federal Register**. Parties are hereby placed on notice that if this proposal is adopted, the reasonableness of a rate reflected in a bilateral agreement entered into after this date will be treated as a confidential contract governed by section 10709 and outside the Board's jurisdiction.

Our proposed changes to the Code of Federal Regulations are set forth in the appendix. Parties are specifically invited to comment on the proposed rules, particularly concerning 49 CFR 1313.1(c). Parties are asked to consider whether the proposed changes would have unforeseen consequences for agricultural contracts and whether there are differences between agricultural and other types of rail transportation contracts.

Pursuant to 5 U.S.C. 605(b), the Board certifies that this action will not have a significant economic effect on a substantial number of small entities within the meaning of the Regulatory Flexibility Act.

This action will not significantly affect either the quality of the human environment or the conservation of energy resources.

Authority: 49 U.S.C. 721, 49 U.S.C. 10709.

Decided: March 28, 2007.

By the Board, Chairman Nottingham, Vice Chairman Buttrey, and Commissioner Mulvey.

Vernon A. Williams,

Secretary.

For the reasons set forth in the preamble, the Surface Transportation Board proposes to amend part 1300 and 1313 of title 49, chapter x, of the Code of Federal Regulations as follows:

PART 1300—DISCLOSURE, PUBLICATION, AND NOTICE OF CHANGE OF RATES AND OTHER SERVICE TERMS FOR RAIL COMMON CARRIAGE

1. The authority citation for Part 1300 continues to read as follows:

Authority: 49 U.S.C. 721(a) and 11101(f).

2. Amend § 1300.1 by adding paragraphs (c)(1) and (c)(2) to read as follows:

§ 1300.1 Scope; definitions.

* * * * *

(c) * * *

(1) The term *contract* in 49 U.S.C. 10709 is defined as any bilateral agreement between a carrier and a shipper for rail transportation in which the carrier agrees to a specific rate for a specific period of time in exchange for consideration from the shipper, such as a commitment to tender a specific amount of freight during a specific period or to make specific investments in rail facilities.

(2) Notwithstanding any representation that a rate specified in an agreement is a common carrier rate, a bilateral agreement as described in paragraph (c)(1) of this section will be treated by the Board as a rail transportation contract authorized under 49 U.S.C. 10709 and therefore outside the Board's jurisdiction.

* * * * *

PART 1313—RAILROAD CONTRACTS FOR THE TRANSPORTATION OF AGRICULTURAL PRODUCTS

3. The authority citation for Part 1313 continues to read as follows:

Authority: 49 U.S.C. 721(a) and 10709.

4. Amend § 1313.1 by revising the first sentence of paragraph (c) to read as follows:

§ 1313.1 Scope; definitions of terms.

* * * * *

(c) For purposes of this part, the term *contract* means a contract as defined in 49 CFR 1300.1(c), including any amendment thereto, to provide specified transporation of agricultural products (including grain, as defined in 7 U.S.C. 75 and products thereof). * * *

[FR Doc. E7–6215 Filed 4–3–07; 8:45 am]

BILLING CODE 4915–01–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 635

[Docket No. 070330073–7073–01; I.D. 030507A]

RIN 0648–AU87

Atlantic Highly Migratory Species; Atlantic Bluefin Tuna Quota Specifications and Effort Controls

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

ACTION: Proposed rule; request for comments; notice of public hearings.

SUMMARY: NMFS proposes initial 2007 fishing year specifications for the Atlantic bluefin tuna (BFT) fishery to set BFT quotas for each of the established domestic fishing categories and to set effort controls for the General category and Angling category. This action is necessary to implement recommendations of the International Commission for the Conservation of Atlantic Tunas (ICCAT), as required by the Atlantic Tunas Convention Act (ATCA), and to achieve domestic management objectives under the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act). A minor administrative change to the permit regulations is also proposed. NMFS solicits written comments and will hold public hearings in April 2007 to receive oral comments on these proposed actions.

DATES: Written comments must be received on or before May 4, 2007.

The public hearings dates are:

1. April 24, 2007, 7 p.m. to 9 p.m., Morehead City, NC.

2. April 26, 2007, 6:30 p.m. to 8:30 p.m., West Islip, NY.

3. April 27, 2007, 3:30 p.m. to 5:30 p.m., Gloucester, MA.

ADDRESSES: Comments may be submitted through any of the following methods:

• E-mail: *07BFTSPECS@noaa.gov*. Include in the subject line the following identifier: ''Comments on 2007 Atlantic bluefin tuna specifications.''

• Federal e-Rulemaking Portal: *http://www.regulations.gov*.

• Mail: Sarah McLaughlin, Highly Migratory Species Management Division, Office of Sustainable Fisheries (F/SF1), NMFS, One Blackburn Dr., Gloucester, MA 01930.

• Fax: (978) 281–9340.

The hearing locations are:

1. Morehead City — Carteret Community College (Joselyn Hall, H.J. McGee, Jr. Building), 3505 Arendell Street, Morehead City, NC 28557.

2. West Islip — West Islip Public Library, 3 Higbie Lane, West Islip, NY 11795.

3. Gloucester — NMFS, One Blackburn Drive, Gloucester, MA 01930.

Supporting documents including the Environmental Assessment, Initial Regulatory Flexibility Analysis, and Regulatory Impact Review are available by sending your request to Sarah McLaughlin at the mailing address specified above.

FOR FURTHER INFORMATION CONTACT: Sarah McLaughlin, 978–281–9260.

SUPPLEMENTARY INFORMATION: Atlantic tunas are managed under the dual authority of the Magnuson-Stevens Act and the ATCA. The ATCA authorizes the Secretary of Commerce (Secretary) to promulgate regulations, as may be necessary and appropriate, to implement ICCAT recommendations. The authority to issue regulations under the Magnuson-Stevens Act and the ATCA has been delegated from the Secretary to the Assistant Administrator for Fisheries, NOAA (AA).

Background

On May 28, 1998, NMFS published in the **Federal Register** (64 FR 29090) final regulations, effective July 1, 1999, implementing the Fishery Management Plan for Atlantic Tunas, Swordfish, and Sharks (1999 FMP). On October 2, 2006, NMFS published in the **Federal Register** (71 FR 58058) final regulations, effective November 1, 2006, implementing the Consolidated Atlantic Highly Migratory Species Fishery Management Plan (Consolidated HMS FMP), which consolidates the management of all Atlantic HMS (i.e., sharks, swordfish, tunas, and billfish) into one comprehensive FMP.

The initial specifications within this proposed rule are published in accordance with the Consolidated HMS FMP and are necessary to implement the 2006 ICCAT quota recommendation, as required by the ATCA, and to achieve domestic management objectives under the Magnuson-Stevens Act. This proposed rule would: (1) Establish initial quota specifications consistent with the BFT rebuilding program by allocating the 2006 ICCAT-recommended quota for the 2007 fishing year (June 1, 2007 - December 31, 2007, pursuant to the change in fishing year to a calendar year as of January 2008 per the Consolidated HMS FMP); (2) establish General category effort controls, including time-period subquotas, restricted fishing days (RFDs), and the initial retention limit; and (3) establish Angling category retention limits for the 2007 fishing season. A minor administrative change to the permit regulations is also proposed to allow additional flexibility during conversion back from a fishing year to a calendar year.

Overall U.S. landings figures for the 2006 fishing year are still preliminary and may be updated before these 2007 fishing year specifications are finalized. The specifications and effort controls may subsequently be adjusted during the course of the fishing year, consistent with the provisions of the Consolidated HMS FMP, and, as appropriate, would be published in the **Federal Register**.

NMFS has prepared a draft Environmental Assessment (EA), Regulatory Impact Review (RIR), and an Initial Regulatory Flexibility Analysis (IRFA) which present and analyze anticipated environmental, social, and economic impacts of several alternatives for each of the major issues contained in this proposed rule. The complete list of alternatives and their analysis is provided in the draft EA/RIR/IRFA, and is not repeated here in its entirety. A copy of the draft EA/RIR/IRFA prepared for this proposed rule is available from NMFS (see **ADDRESSES**).

2006 ICCAT Recommendation, BFT Underharvests, and Transfers to Other ICCAT Contracting Parties

At its 2006 meeting, ICCAT recommended a western Atlantic BFT Total Allowable Catch (TAC) of 2,100 mt, to allow for continued rebuilding of BFT through 2018. The TAC is inclusive of dead discards and will be effective annually for 2007 through 2008, and thereafter until changed. The following deductions are made from the TAC prior to applying the U.S. share percentage: 4 mt for the United Kingdom (in respect of Bermuda), 4 mt for France (in respect of St. Pierre and Miquelon), 25 mt for Mexico (to allow incidental catch in the longline fishery in the Gulf of Mexico), and 15 mt for Canada and 25 mt for the United States (for bycatch related to directed longline fisheries in the ''in the vicinity of the management boundary area,'' i.e., the Northeast Distant gear restricted area (NED), which was defined in the 2003 BFT annual specification rulemaking process as the Northeast Distant statistical area (68 FR 56783, October 2, 2003). The U.S. share of the adjusted TAC is 57.48 percent, or 1,165.12 mt. Accounting for the 25 mt NED set-aside, the total U.S. allocation is 1,190.12 mt. The previous (2002) ICCAT recommendation for a western Atlantic BFT TAC of 2,700 mt included a U.S. quota of 1,464.6 mt, which was effective from 2003 through the end of the 2006 fishing year, i.e., May 31, 2007, and also included a 25–mt NED set-aside, for a total of 1,489.6 mt.

The 2006 ICCAT recommendation also includes provisions to: (1) limit carryover of underharvest to no more than 50 percent of a contracting party's initial TAC; (2) limit mortality of school BFT to an average of 10 percent of the initial TAC, calculated on a four-year basis; and (3) allow a contracting party with a TAC allocation to make a one-time transfer within a fishing year of up to 15 percent of its TAC allocation to other contracting parties with TAC allocations, consistent with domestic obligations and conservation considerations. Regarding the third provision, the ICCAT recommendation stipulates that the quota transfer may not be used to cover overharvests, and that a contracting party that receives a one-time quota transfer may not retransfer that quota. For the United States, the 15–percent limit on quota transfer equates to 178.5 mt. In considering whether the United States could enter into an arrangement with another ICCAT contracting party, several factors would need to be taken into account, including, but not limited to, the amount of quota to be transferred, the projected ability of U.S. vessels to harvest the U.S. TAC before the end of the fishing year, the potential benefits of the transfer to U.S. fishing participants (such as access to the EEZ of the receiving contracting party for the harvest of a designated amount of BFT), potential ecological impacts, and the contracting party's ICCAT compliance status. NMFS intends to undertake any transfer of U.S. quota to another ICCAT contracting party via a separate action proposed in the **Federal Register**, if the situation arises.

Initial landings estimates (as of January 15, 2007) per category are as follows: General category — 159.8 mt; Harpoon category — 22.2 mt; Longline category — 31.4 mt; Angling category — 186.8 mt; Trap category — 0 mt; and Purse Seine category — 3.6 mt. These preliminary landings estimates, totaling 403.8 mt, indicate that the total 2006 underharvest is 2,435.4 mt. Underharvests per category are preliminarily determined to be as follows: General category — 1,003.5 mt; Harpoon category — 101.8 mt; Longline category — 236.6 mt; Angling category — 195.2 mt; Trap category — 5.3 mt; and Purse Seine category — 620.5 mt. Based on the estimated amount of Reserve that NMFS maintains for the landing of BFT taken during ongoing scientific research projects and/or potential overharvests in certain categories, NMFS estimates that 282.3 mt of Reserve remains from the 2006 fishing year.

In anticipation of a cap on carryover for the 2007 fishing year, i.e., 595.1 mt, or one half of the initial U.S. TAC of 1,190.12 mt, and in anticipation of a substantial underharvest of the 2006 fishing year domestic quota, the United States agreed at the 2006 ICCAT meeting to transfer a total of 275 mt of current U.S. underharvest (i.e., underharvest of the 2006 fishing year quota) as follows: 75 mt and 100 mt for 2007 and 2008, respectively, to Mexico, and 50 mt for each of the years 2007 and 2008 to Canada. Based on these transfers, the remaining amount of underharvest (as of

January 15, 2007) is 2,160.4 mt. However, the ICCAT-recommended cap limits the amount the United States may carry over for 2007 to 595.1 mt.

Domestic Quota Allocation

The 1999 FMP and its implementing regulations established baseline percentage quota shares for the domestic fishing categories. These percentage shares were based on allocation procedures that NMFS developed over several years. The baseline percentage quota shares established in the 1999 FMP and contained in the Consolidated HMS FMP for fishing years beginning June 1, 1999, and continuing to the present are as follows: General category — 47.1 percent; Harpoon category — 3.9 percent; Purse Seine category — 18.6 percent; Angling category — 19.7 percent; Longline category — 8.1 percent; Trap category — 0.1 percent; and Reserve category — 2.5 percent.

These proposed initial 2007 fishing year specifications, consistent with the BFT rebuilding program, would allocate the 2006 ICCAT-recommended quota for the 2007 fishing year among the several established domestic fishing categories based on the current BFT quota allocation percentages per the Consolidated HMS FMP, and would allocate 25 mt to the longline north NED subquota.

As described further below, these specifications also would apply 595.1 mt of the underharvest of BFT quota from the 2006 fishing year, consistent with the ICCAT-recommended 50–percent cap on quota carryover to the 2007 fishing year quota, and distribute that underharvest in such a manner to: (1) Allow for potential transfer of a portion (up to 15 percent) of the 2007 U.S. quota to other ICCAT Contracting Parties, if warranted; (2) ensure that the Longline category has sufficient quota to operate during the 2007 fishing year while also considering accounting for BFT discards; and (3) provide the non-Longline quota categories a share of the remainder of the underharvest consistent with the allocation scheme established in the Consolidated HMS FMP.

Beginning with its 1998 recommendation, ICCAT has historically recommended a deduction of 79 mt from the TAC as an allowance for dead discards, and the U.S. portion of this allowance has been 68 mt. The 2006 ICCAT recommendation included neither a recommended dead discard allowance, nor specified dead discard reporting methodology for compliance purposes. Nevertheless, the United States must report dead discard estimates annually. Accordingly, NMFS must account for BFT dead discards in setting the 2007 fishing year quota.

In the past, for compliance purposes, the United States has reported dead discards to ICCAT as an estimate based on pelagic longline vessel logbook tallies, adjusted as warranted by observer data. For 2005, the most recent year for which complete information is available, the estimate is approximately 46 mt. However, based on revised methodology, the SCRS now reports dead discard estimates generated via extrapolation of logbook tallies by pooled observer data; for 2005, the estimate is approximately 131 mt. These specifications also use this revised estimate. Estimates of dead discards from other gear types and fishing sectors that do not use the pelagic longline vessel logbook are unavailable at this time and thus are not included in this calculation. Per the ICCAT recommendation, which specifies a U.S. quota that is inclusive of dead discards, and consistent with how NMFS has handled past incidents of dead discards exceeding the allowance, NMFS would deduct the 131 mt of estimated dead discards from the amount of quota available for the Longline category for the 2007 fishing year. In addition, NMFS proposes to modify the BFT quota and annual adjustment regulations at § 635.27(a) to indicate that NMFS will account for dead discards annually as part of the specifications process, and to indicate its intent to subtract that amount from the quota of the category accounting for the dead discards.

As described above, the United States may choose, pursuant to the 2006 ICCAT recommendation, to transfer up to 15 percent of the U.S. TAC to another ICCAT Contracting Party with a TAC allocation, consistent with U.S. obligations and conservation considerations. NMFS proposes to divide the 595.1 mt of quota carryover such that 178.5 mt (i.e., 15 percent of 1,190.12 mt) is placed in the Reserve for potential ICCAT transfer purposes.

NMFS also proposes to assign a sufficient amount of the quota carryover (236.6 mt) to the Longline category, due to the revised dead discard accounting methodology, so that after accounting for the 131 mt of dead discards, sufficient quota is available to cover the anticipated landings and dead discards of the pelagic longline fishery during the 2007 fishing year, i.e., potentially 200 mt. NMFS seeks to avoid a zero or negative quota for the Longline category, which could result in increased BFT discards, given that NMFS must subtract the best available dead discard estimate from the TAC on an annual basis. The Longline category baseline quota allocation (currently 8.1 percent of the TAC) may need to be revisited in the near future. Any change to the baseline allocation would require an amendment to the Consolidated HMS FMP. NMFS proposes to distribute the remainder of the quota carryover (180 mt) to the Angling, General, Harpoon, Purse Seine, and Trap categories consistent with their FMP allocations.

Consistent with the 2006 ICCAT recommendation, the proposed rule also would increase the limit on the take of school BFT (measuring 27 inches (68.6 cm) to less than 47 inches (119.4 cm)) over each 4–consecutive-year period from 8 percent of the total U.S. TAC (per the 2002 ICCAT recommendation) to 10 percent. Because the total U.S. quota is reduced by 22 percent, there will be only a minor effective increase in the base school BFT quota, in weight.

2007 Proposed Initial Quota Specifications

In accordance with the 2006 ICCAT quota recommendation, the Consolidated HMS FMP percentage shares for each of the domestic categories, and regulations regarding annual adjustments at § 635.27(a)(10)(ii), NMFS proposes initial quota specifications for the 2007 fishing year as follows: General category — 643.6 mt; Harpoon category — 53.3 mt; Purse Seine category — 254.1 mt; Angling category — 269.2 mt; Longline category — 200 mt; and Trap category — 1.4 mt. Additionally, 207.6 mt would be allocated to the Reserve category for inseason adjustments, scientific research collection, potential overharvest in any category except the Purse Seine category, and potential quota transfers.

Based on the above proposed initial specifications and considerations regarding the school BFT fishery, the Angling category quota of 269.2 mt would be further subdivided as follows: School BFT — 119 mt, with 45.8 mt to the northern area (north of 39°18′ N. latitude), 51.2 mt to the southern area (south of 39°18′ N. latitude), plus 22 mt held in reserve; large school/small medium BFT — 144 mt, with 68 mt to the northern area and 76 mt to the southern area; and large medium/giant BFT — 6.2 mt, with 2.1 mt to the northern area and 4.2 mt to the southern area.

The 25–mt NED set-aside quota is in addition to the overall incidental longline quota to be subdivided in accordance with the North/South allocation percentages (i.e., no more than 60 percent to the south of 31° N. latitude). Thus, the proposed Longline

category quota of 200 mt would be subdivided as follows: 80 mt to pelagic longline vessels landing BFT north of 31° N. latitude and 120 mt to pelagic longline vessels landing BFT south of 31° N. latitude, with 25 mt set-aside for bycatch of BFT related to directed pelagic longline fisheries in the NED. NMFS would account for landings under this additional quota separately from other landings under the Longline north subcategory.

General Category Effort Controls

For the last several years, NMFS has implemented General category time-period subquotas to increase the likelihood that fishing would continue throughout the entire General category season. The subquotas are consistent with the objectives of the Consolidated HMS FMP and are designed to address concerns regarding the allocation of fishing opportunities, to assist with distribution and achievement of optimum yield, to allow for a late season fishery, and to improve market conditions and scientific monitoring.

The regulations implementing the Consolidated HMS FMP divide the annual General category quota into five time-period subquotas as follows: 50 percent for June-August, 26.5 percent for September, 13 percent for October-November, 5.2 percent for December, and 5.3 percent for January. Because the fishing year is changing back to a calendar year effective January 1, 2008, NMFS proposes, for the 2007 fishing year only, to distribute the 5.3 percent of the General category quota that would be assigned to the January time period to the four time periods that will occur during the 2007 fishing year. Therefore, of the available 643.6–mt coastwide quota, 339.8 mt would be available in the period beginning June 1 and ending August 31, 2007; 180.1 mt would be available in the period beginning September 1 and ending September 30, 2007; 88.4 mt would be available in the period beginning October 1 and ending November 30, 2007; and 35.3 mt would be available in the period beginning December 1 and ending December 31, 2007. The January 2007 BFT fishery was prosecuted using 2006 fishing year quota. The January 2008 subquota will be included in the 2008 specifications, which NMFS plans to publish prior to the start of the fishery on January 1, 2008. As discussed in the Consolidated HMS FMP, NMFS plans to work with the affected constituents through the 2008 specifications process to determine the most appropriate disposition of any under- or overharvest that has accrued in the General category by the end of December 2007.

In addition to time-period subquotas, NMFS also implements General category RFDs to extend the General category fishing season. The RFDs are designed to address the same issues addressed by time-period subquotas and provide additional fine scale inseason flexibility. For the 2007 fishing year, NMFS proposes a series of solid blocks of RFDs to extend the General category for as long as possible through the end of the 2007 fishing year.

Therefore, NMFS proposes that persons aboard vessels permitted in the General category would be prohibited from fishing, including catch-and-release and tag-and-release, for BFT of all sizes on the following days: all Saturdays and Sundays from November 17, 2007, through December 31, 2007, plus November 22 and December 25, 2007, while the fishery is open. These proposed RFDs would distribute fishing opportunities during the late season without increasing BFT mortality. NMFS' intention is to propose RFDs for January 2008 as part of the 2008 quota specifications and effort controls, scheduled to be published before January 1, 2008.

Finally, NMFS proposes to adjust the General category retention limit to three BFT (73 inches (185.4 cm) or greater per vessel per day/trip). This action is intended to allow increased opportunities to harvest the General category quota during the period when catch rates have historically been slow, and to avoid accumulation of unused quota. This retention limit would be effective from June 1, 2007, until August 31, 2007, unless adjusted with an inseason action, if necessary. NMFS may consider further retention limit adjustments after August 31, 2007, depending on several factors, including but not limited to catch rates and availablility of quota.

Angling Category Effort Controls

NMFS proposes to adjust the Angling category retention limit to one school BFT (27 inches (68.6 cm) to less than 47 inches (119.4 cm)), and two large school/small medium BFT (i.e., two BFT measuring 47 inches (119.4 cm) to less than 73 inches (185.4 cm)) per vessel per day/trip. This limit is expected to maximize use of the Angling category quota while avoiding overharvest of each of the Angling catgeory subquotas. The alternative also would provide the same retention limit for both private and charter/headboat vessels.

Permit Category Changes

Because of the scheduled change to a calendar year fishery beginning January 1, 2008, and because NMFS plans to administer the permit program such that Atlantic Tunas, HMS Charter/Headboat, and HMS Angling category permits issued for the 2007 fishing year will be effective through December 31, 2008, NMFS also proposes to extend the window of opportunity to change permit categories for the 2008 fishing year, i.e., once during the period of January 1, 2008, through May 31, 2008.

Classification

This proposed rule is published under the authority of the Magnuson-Stevens Act and the ATCA. The AA has preliminarily determined that the regulations contained in this proposed rule are necessary to implement the recommendations of ICCAT and to manage the domestic Atlantic HMS fisheries.

This proposed rule has been determined to be not significant for purposes of Executive Order 12866.

An IRFA was prepared, as required by section 603 of the Regulatory Flexibility Act. The IRFA describes the economic impact this proposed rule, if adopted, would have on small entities. A description of the action, why it is being considered, and the legal basis for this action are contained in the preamble to this proposed rule. A summary of the analysis follows. A copy of this analysis is available from NMFS (see **ADDRESSES**).

NMFS has prepared this IRFA to analyze the impacts on small entities of the alternatives for establishing 2007 fishing year BFT quotas for all domestic fishing categories and General and Angling category effort controls. The analysis for the IRFA assesses the impacts of the various alternatives on the vessels that participate in the BFT fisheries, all of which are considered small entities. In order to do this, NMFS has estimated the average impact that the alternatives to establish the 2007 BFT quota for all domestic fishing categories would have on individual categories and the vessels within those categories. As mentioned above, the 2006 ICCAT recommendation reduced the U.S. BFT TAC to 1,190.12 mt. This quota allocation includes a set-aside quota of 25 mt to account for incidental catch of BFT related to directed longline swordfish and non-BFT tuna fisheries in the NED. This action would distribute the adjusted (baseline) TAC of 1,165.1 mt to the domestic fishing categories based on the allocation percentages established in the Consolidated HMS FMP.

In 2006, the annual gross revenues from the commercial BFT fishery were approximately $3.4 million.

Approximately 8,751 vessels are permitted to land and sell BFT under four commercial BFT quota categories (including charter/headboat vessels). The commercial categories and their 2006 gross revenues are General ($2.5 million), Harpoon ($265,951), Purse Seine ($33,819), and Longline ($558,022). The IRFA assumes that vessels within a category will have similar catch and gross revenues in order to consider the relative impact of the various preferred alternatives on vessels. Data on net revenues of individual fishermen are lacking, so the economic impact of the alternatives is averaged across each category. NMFS considers this a reasonable approach for BFT fisheries. More specifically, available landings data (weight and ex-vessel value of the fish in price/pound) allow NMFS to calculate the gross revenue earned by a fishery participant on a successful trip. The available data do not, however, allow NMFS to calculate the effort and cost associated with each successful trip (e.g., the cost of gas, bait, ice, etc.) so net revenue for each participant cannot be calculated. NMFS cannot determine whether net revenue varies among individual fishery participants within each category, and therefore whether the economic impact of a regulation would have a varying impact among individual participants. As a result, NMFS analyzes the average impact of the proposed alternatives among all participants in each category.

For the allocation of BFT quota among domestic fishing categories, NMFS considered three alternatives: A no action alternative (A1); Alternative A2 (the preferred alternative), which would implement the 2006 ICCAT recommendation; and Alternative A3, which would allocate the 2006 ICCAT recommendation in a manner other than that designated in the Consolidated HMS FMP and which could address issues regarding the changing nature of the BFT fisheries (e.g., allocate additional quota to certain categories and/or certain geographic regions). Alternative A3 would result in a de facto quota reallocation among categories, and an FMP amendment would be necessary for its implementation. Per the Consolidated HMS FMP, NMFS prepares quota specifications annually for the upcoming fishing year. Preparation of an FMP amendment would not be possible in the brief period of time between receipt of the ICCAT recommendation, which occurred in late November 2006, and the start of the 2007 fishing year on June 1, 2007. Therefore, analysis of the impacts of Alternative A3 is not available. But, if an FMP amendment was feasible, positive economic impacts would be expected to result on average for vessels in permit categories that would receive a greater share than established in the FMP, and negative economic impacts would be expected to result on average for vessels in permit categories that would receive a lesser share than established in the FMP. Impacts per vessel would depend on the temporal and spatial availability of BFT to participants.

As noted above, the preferred alternative (Alternative A2) would implement the 2006 ICCAT recommendation in accordance with the Consolidated HMS FMP and consistent with the ATCA, under which the United States is obligated to implement ICCAT-approved quota recommendations. Alternative A2 would have slightly positive impacts for fishermen. The no action alternative would keep the quota at pre–2006 ICCAT recommendation levels (approximately 300 mt more) and would not be consistent with the purpose and need for this action and the Consolidated HMS FMP. It would maintain economic impacts to the United States and to local economies at a distribution and scale similar to 2006 or recent prior years, and would provide fishermen additional fishing opportunities, subject to the availability of BFT to the fishery, in the short term.

The preferred alternative also would implement the provision of the 2006 ICCAT recommendation that limits tolerance for school BFT landings to 10 percent of the U.S. TAC, calculated on a four-year average. This is expected to have neutral impacts on fishermen who fish for school BFT, particularly those who rely exclusively on the school size class for BFT harvest, since the available quota is the same as the level when the limit was 8–percent of the U.S. TAC under the 2002 ICCAT recommendation.

Two alternatives were considered for effort control using RFDs in the General category. The no action alternative would not implement any RFDs with publication of the initial specifications but rather would use inseason management authority established in the Consolidated HMS FMP to implement RFDs during the season, should catch rates warrant taking this approach. This alternative could be most beneficial during a season of low catch rates and could have positive economic consequences if slow catch rates were to persist during the late season fishery. During a slow season, the season could regulate itself and fishermen could choose when to fish or not based on their own preferences. However, it is impossible to predict in advance whether the season will have low or high catch rates.

The preferred alternative would designate RFDs according to a schedule published in the initial BFT specifications. In the past, when catch rates have been high, the use of RFDs (preferred alternative) has had positive economic consequences by avoiding oversupplying the market and extending the season as late as possible. In addition, establishing RFDs at the season onset provides better planning opportunities than implementing RFDs during the season, since charter/headboat businesses could book trips and recreational and commercial fishermen could make plans ahead of time rather than waiting until the last minute to see if an RFD is going to be implemented. However, implementing RFDs to extend the late season may have some negative economic impacts to northern area fishermen who choose to travel to the southern area during the late season fishery. Travel and lodging costs may be greater if the season were extended over a greater period of time as proposed under the preferred alternative. Those additional costs could be mitigated if the ex-vessel price of BFT stays high, as is intended under this alternative. Without RFDs, travel costs may be less because of a shorter season; however, the market could be oversupplied and ex-vessel prices could fall. Overall, extending the season as late as possible and establishing formalized RFDs at the season onset would enhance the likelihood of increasing participation by southern area fishermen, increase access to the fishery over a greater range of the fish migration, provide a reliable mechanism for slowing a fishery that has an ability to generate extremely high catch rates, and is expected to provide better than average ex-vessel prices with an overall increase in gross revenues.

A retention limit of three BFT (measuring 73 inches (185.4 cm) or greater per vessel per day/trip) is the preferred alternative for the opening retention limit for the General category, which would be in effect through August 31, 2007. This alternative is expected to result in the most positive socio-economic impacts by providing the best opportunity to harvest the quota while avoiding oversupplying the market, thus maximizing gross revenues. Other considered alternatives were the no action alternative (one BFT measuring 73 inches or greater per vessel per day/trip) and a retention limit of two BFT (73 inches or greater per vessel per day/trip). Both of these alternatives are expected to be too

restrictive given the large amount of quota available for the General category during the 2007 fishing year and could result in the negative economic impact of lower gross revenues. Although early season landings seldom occur at a rate that could oversupply the market, NMFS will monitor landings closely to ensure that the increased retention limit does not contribute to an oversupply.

Six alternatives were considered for Angling category retention limits for the 2007 fishing year. The preferred alternative (D1b) is a three BFT retention limit (two fish measuring 47 inches (119.4 cm) to less than 73 inches (185.4 cm) and one fish measuring 27 inches (68.6 cm) to less than 73 inches) per vessel per day/trip for all sectors of the Angling category for the entire 2007 fishing year. The other two alternatives providing the same daily retention limits (per vessel) for both private recreational and charter/headboats were the no action alternative (D1a, i.e., one fish measuring 27 inches to less than 73 inches) and Alternative D1c (two fish measuring 47 inches to less than 73 inches and two fish measuring 27 inches to less than 73 inches). Alternative D1a was not preferred because it could unnecessarily restrict the amount of Angling category landings which could result in an underharvest of the quota and a negative economic impact. Alternative D1c was not preferred because it could result in an overharvest of the quota, with negative economic consequences.

Three other alternatives were considered that would provide different retention limits for the Angling category sectors. The first (D2a) would allow a private vessel daily retention limit of three fish (two measuring 47 inches to less than 73 inches and one measuring 27 inches to less than 47 inches) and a charter/headboat daily retention limit (per vessel) of five fish (three fish measuring 47 inches to less than 73 inches and two fish measuring 27 inches to less than 47 inches). The second alternative (D2b) would allow three fish (two measuring 47 inches to less than 73 inches and one measuring 27 inches to less than 47 inches) for each vessel per day/trip for the season, with an increase to five fish (three measuring 47 inches to less than 73 inches and two measuring 27 inches to less than 47 inches) per vessel for charter/headboats during June 15, 2007 through July 31, 2007, and the month of September 2007. The third alternative (D2c) would allow two fish (measuring 27 inches to less than 73 inches) less than 47 inches) for each vessel per day/trip for the season, with an increase to three fish (measuring 27 inches to less than 73 inches) per vessel for charter/headboats during June 15, 2007 through July 31, 2007, and the month of September 2007. Alternatives D2a and D2b were considered to be potentially too liberal with a greater potential for exceeding the Angling category quota for 2007. Alternative D2c was considered to be unnecessarily restrictive with a greater potential for negative economic impacts associated with not harvesting the entire quota. In addition, the D2 subalternatives were not preferred since they could result in perceived inequities between the two sectors of the Angling category fishery.

The preferred alternative (D1b) was selected to balance the intent of landing the Angling category quota without overharvesting, providing sufficient retention limits to offset costs, reducing any perceived inequities between the charter/headboat and private recreational vessel sectors of the Angling category fishery, and providing economic benefits to all regional sectors of the fishery.

There are no new reporting or recordkeeping requirements contained in any of the alternatives considered for this action. This proposed rule has also been determined not to duplicate, overlap, or conflict with any other Federal rules.

List of Subjects in 50 CFR Part 635

Fisheries, Fishing, Fishing vessels, Foreign relations, Management, Treaties.

Dated: March 30, 2007.

Samuel D. Rauch III

Deputy Assistant Administrator for Regulatory Programs, National Marine Fisheries Service.

For the reasons set out in the preamble, 50 CFR part 635 is proposed to be amended as follows:

PART 635—ATLANTIC HIGHLY MIGRATORY SPECIES

1. The authority citation for part 635 continues to read as follows:

Authority: 16 U.S.C. 971 *et seq.*; 16 U.S.C. 1801 *et seq.*

2. In § 635.4, paragraph (j)(3) is revised to read as follows:

§ 635.4 Permits and fees.

* * * * *

(j) * * *

(3) A vessel owner issued an Atlantic tunas permit in the General, Harpoon, or Trap category or an Atlantic HMS permit in the Angling or Charter/Headboat category under paragraph (b), (c), or (d) of this section may change the category of the vessel permit once within 10 calendar days of the date of issuance of the permit. After 10 calendar days from the date of issuance of the permit, the vessel owner may not change the permit category until the following fishing season, except during the period of January 1, 2008, through May 31, 2008, when one additional change is authorized.

* * * * *

3. In § 635.27, paragraphs (a) introductory text, (a)(1)(i), (a)(2), (a)(3), (a)(4)(i), (a)(5), (a)(6), (a)(7)(i), (a)(7)(ii), (a)(10)(iii), and (a)(10)(iv) are revised to read as follows:

§ 635.27 Quotas.

(a) *BFT.* Consistent with ICCAT recommendations, and with paragraph (a)(10)(iv) of this section, NMFS may subtract the most recent, complete, and available estimate of dead discards from the annual U.S. BFT quota, and make the remainder available to be retained, possessed, or landed by persons and vessels subject to U.S. jurisdiction. The remaining baseline annual U.S. BFT quota will be allocated among the General, Angling, Harpoon, Purse Seine, Longline, Trap, and Reserve categories. BFT may be taken by persons aboard vessels issued Atlantic Tunas permits, HMS Angling permits, or HMS Charter/Headboat permits. The baseline annual U.S. BFT quota is 1,165.1 mt, not including an additional annual 25 mt allocation provided in paragraph (a)(3) of this section. Allocations of the baseline annual U.S. BFT quota are: General - 47.1 percent (548.8 mt); Angling - 19.7 percent (229.5 mt), which includes the school BFT held in reserve as described under paragraph (a)(7)(ii) of this section; Harpoon - 3.9 percent (45.4 mt); Purse Seine - 18.6 percent (216.7 mt); Longline - 8.1 percent (94.4 mt), which does not include the additional annual 25 mt allocation provided in paragraph (a)(3) of this section; and Trap - 0.1 percent (1.2 mt). The remaining 2.5 percent (29.1 mt) of the baseline annual U.S. BFT quota will be held in reserve for inseason or annual adjustments based on the criteria in paragraph (a)(8) of this section. NMFS may apportion a quota allocated to any category to specified fishing periods or to geographic areas and will make annual adjustments to quotas, as specified in paragraph (a)(10) of this section. BFT quotas are specified in whole weight.

(1) *General category quota.* * * *

(i) Catches from vessels for which General category Atlantic Tunas permits have been issued and certain catches from vessels for which an HMS Charter/Headboat permit has been issued are counted against the General category quota in accordance with § 635.23(c)(3).

The amount of large medium and giant BFT that may be caught, retained, possessed, landed, or sold under the General category quota is 47.1 percent (548.8 mt) of the baseline annual U.S. BFT quota, and is apportioned as follows:

(A) January 1 through January 31 - 5.3 percent (29.1 mt);

(B) June 1 through August 31 - 50 percent (274.4 mt);

(C) September 1 through September 30 - 26.5 percent (145.4 mt);

(D) October 1 through November 30 - 13 percent (71.3 mt); and

(E) December 1 through December 31 - 5.2 percent (28.5 mt).

* * * * *

(2) *Angling category quota.* In accordance with the framework procedures of the HMS FMP, prior to each fishing year or as early as feasible, NMFS will establish the Angling category daily retention limits. The total amount of BFT that may be caught, retained, possessed, and landed by anglers aboard vessels for which an HMS Angling permit or an HMS Charter/Headboat permit has been issued is 19.7 percent (229.5 mt) of the baseline annual U.S. BFT quota. No more than 2.3 percent (5.3 mt) of the annual Angling category quota may be large medium or giant BFT. In addition, over each 4 consecutive-year period (starting in 2007, inclusive), no more than 10 percent of the annual U.S. BFT quota, inclusive of the allocation specified in paragraph (a)(3) of this section, may be school BFT. The Angling category quota includes the amount of school BFT held in reserve under paragraph (a)(7)(ii) of this section. The size class subquotas for BFT are further subdivided as follows:

(i) After adjustment for the school BFT quota held in reserve (under paragraph (a)(7)(ii) of this section), 52.8 percent (51.2 mt) of the school BFT Angling category quota may be caught, retained, possessed, or landed south of 39°18′ N. lat. The remaining school BFT Angling category quota (45.8 mt) may be caught, retained, possessed or landed north of 39°18′ N. lat.

(ii) An amount equal to 52.8 percent (55.6 mt) of the large school/small medium BFT Angling category quota may be caught, retained, possessed, or landed south of 39°18′ N. lat. The remaining large school/small medium BFT Angling category quota (49.6 mt) may be caught, retained, possessed or landed north of 39°18′ N. lat.

(iii) An amount equal to 66.7 percent (3.5 mt) of the large medium and giant BFT Angling category quota may be caught, retained, possessed, or landed south of 39°18′ N. lat. The remaining large medium and giant BFT Angling category quota (1.8 mt) may be caught, retained, possessed or landed north of 39°18′ N. lat.

(3) *Longline category quota.* The total amount of large medium and giant BFT that may be caught incidentally and retained, possessed, or landed by vessels that possess Longline category Atlantic Tunas permits is 8.1 percent (94.4 mt) of the baseline annual U.S. BFT quota. No more than 60.0 percent of the Longline category quota may be allocated for landing in the area south of 31°00′ N. lat. In addition, 25 mt shall be allocated for incidental catch by pelagic longline vessels fishing in the Northeast Distant gear restricted area as specified at § 635.23(f)(3).

(4) * * *

(i) The total amount of large medium and giant BFT that may be caught, retained, possessed, or landed by vessels that possess Purse Seine category Atlantic Tunas permits is 18.6 percent (216.7 mt) of the baseline annual U.S. BFT quota. The directed purse seine fishery for BFT commences on July 15 of each year unless NMFS takes action to delay the season start date. Based on cumulative and projected landings in other commercial fishing categories, and the potential for gear conflicts on the fishing grounds or market impacts due to oversupply, NMFS may delay the BFT purse seine season start date from July 15 to no later than August 15 by filing an adjustment with the Office of the Federal Register prior to July 1.

* * * * *

(5) *Harpoon category quota.* The total amount of large medium and giant BFT that may be caught, retained, possessed, landed, or sold by vessels that possess Harpoon category Atlantic Tunas permits is 3.9 percent (45.4 mt) of the baseline annual U.S. BFT quota. The Harpoon category fishery closes on November 15 each year.

(6) *Trap category quota.* The total amount of large medium and giant BFT that may be caught, retained, possessed, or landed by vessels that possess Trap category Atlantic Tunas permits is 0.1 percent (1.2 mt) of the baseline annual U.S. BFT quota.

(7) * * *

(i) The total amount of BFT that is held in reserve for inseason or annual adjustments and fishery-independent research using quotas or subquotas is 2.5 percent (29.1 mt) of the baseline annual U.S. BFT quota. Consistent with paragraph (a)(8) of this section, NMFS may allocate any portion of this reserve for inseason or annual adjustments to any category quota in the fishery.

(ii) The total amount of school BFT that is held in reserve for inseason or annual adjustments and fishery-independent research is 18.5 percent (22 mt) of the total school BFT Angling category quota as described under paragraph (a)(2) of this section. This is in addition to the amounts specified in paragraph (a)(7)(i) of this section. Consistent with paragraph (a)(8) of this section, NMFS may allocate any portion of the school BFT Angling category quota held in reserve for inseason or annual adjustments to the Angling category.

* * * * *

(10) * * *

(iii) Regardless of the estimated landings in any year, NMFS may adjust the annual school BFT quota to ensure that the average take of school BFT over each 4 consecutive-year period beginning in the 2007 fishing year does not exceed 10 percent by weight of the total annual U.S. BFT quota, inclusive of the allocation specified in paragraph (a)(3) of this section, for that period.

(iv) NMFS may subtract the best available estimate of dead discards from the amount of BFT that can be landed in the subsequent fishing year by those categories accounting for the dead discards.

* * * * *

[FR Doc. E7–6259 Filed 4–3–07; 8:45 am]

BILLING CODE 3510–22–S

Notices

Federal Register
Vol. 72, No. 64
Wednesday, April 4, 2007

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

[Docket No: AMS–07–0044; CN–07–002]

Notice of Request for an 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 (44 U.S.C. Chapter 35), this notice announces the Agricultural Marketing Service's (AMS) intention to request approval from the Office of Management and Budget, for an extension of and revision to the currently approved information collection Cotton Classification and Market News Service.

DATES: Comments received by June 4, 2007 will be considered.

Additional Information or Comments: Interested persons are invited to submit written comments concerning this proposal to Shethir Riva, Chief, Research and Promotion, Cotton Program, Agricultural Marketing Service, USDA, 1400 Independence Ave., SW., Washington, DC 20250–0224. Comments should be submitted in triplicate. Comments may also be submitted electronically through *www.regulations.gov.* All comments should reference the docket number and page number of this issue of the **Federal Register**. All comments received will be made available for public inspection at Cotton Program, AMS, USDA, Room 2639–S, 1400 Independence Ave., SW., Washington, DC 20250 during regular business hours. A copy of this notice may be found at *http://www.ams.usda.gov/cotton/rulemaking.htm.*

FOR FURTHER INFORMATION CONTACT: Shethir Riva, Chief, Research and Promotion, Cotton Program, Agricultural Marketing Service, USDA, 1400 Independence Ave., SW., Washington, DC 20250–0224, telephone (202) 720–3193, facsimile (202) 690–1718, or e-mail at *Shethir.riva@usda.gov.*

SUPPLEMENTARY INFORMATION:

Title: Cotton Classification and Market News Service.

OMB Number: 0581–0009.

Expiration Date of Approval: September 30, 2007.

Type of Request: Extension and Revision of a Currently Approved Information Collection.

Abstract: The Cotton Classification and Market News Service program provides market information on Cotton prices, quality, stocks, demand and supply to growers, ginners, merchandisers, textile mills and the public for their use in making sound business decisions. The Cotton Statistics and Estimates Act U.S.C. 471–476, authorizes and directs the Secretary of Agriculture to: (a) Collect and publish annually, statistics or estimates concerning the grades and staple lengths of stocks of cotton, known as the carryover, on hand on the 1st of August each year in warehouses and other establishments of every character in the continental U.S., and following such publication each year, to publish at intervals, in his/her discretion, his/her estimate of the grades and staple length of cotton of the current crop (7 U.S.C. 471); (b) Collect, authenticate, publish and distribute by radio, mail, or otherwise, timely information of the market supply, demand, location, and market prices of cotton (7 U.S.C. 473b). The Agricultural Marketing Act of 1946, 7 U.S.C. 1621–1627, authorizes and directs the Secretary of Agriculture to collect and disseminate marketing information, including adequate outlook information on a market-area basis, for the purpose of anticipating and meeting consumer requirements, aiding in the maintenance of farm income, and bringing about a balance between production and utilization of agricultural products.

The information collection requirements in this request are essential to carry out the intent of the Acts and to provide the cotton industry the type of information they need to make sound business decisions. The information collected is the minimum required. Information is requested from growers, cooperatives, merchants, manufacturers, and other government agencies. This includes information on cotton, cottonseed and cotton linters.

The information collected is used only by authorized employees of the USDA, AMS. The Cotton Industry is the primary user of the compiled information and AMS and other government agencies are secondary users.

Estimate of Burden: Public reporting burden for this collection of information is estimated to average 0.13 hours per response.

Respondents: Cotton Merchandisers, Textile Mills, Ginners.

Estimated Number of Respondents: 1,066.

Estimated Number of Responses per Respondent: 8.55.

Estimated Number of Responses: 9,116.13.

Estimated Total Annual Burden on Respondents: 1,161.25.

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. Comments may be sent to Shethir Riva, Chief, Research and Promotion, Cotton Program, Agricultural Marketing Service, USDA, 1400 Independence Ave., SW., Washington, DC 20250–0224. All comments received will be available for public inspection during regular business hours at the same address.

All responses to this notice will be summarized and included in the request for OMB approval. All comments will become a matter of public record.

Dated: March 29, 2007.

Lloyd C. Day,

Administrator, Agricultural Marketing Service.

[FR Doc. E7–6246 Filed 4–3–07; 8:45 am]

BILLING CODE 3410–02–P

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

[Docket No. DA–07–04]

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 (44 U.S.C. Chapter 35), this notice announces the Agricultural Marketing Service's (AMS) intention to request an extension for and revision to a currently approved information collection for report forms under the Federal milk marketing order program.

DATES: Comments on this notice must be received by June 4, 2007 to be assured of consideration.

ADDRESSES: Interested persons are invited to submit written comments on the Internet at *http://www.regulations.gov* or to the Office of the Deputy Administrator, Dairy Programs, AMS, USDA, 1400 Independence Avenue, SW., Room 2968 South, Stop 0225, Washington, DC 20250–0225. Comments should make reference to the date and page number of this issue of the **Federal Register**. All comments will be made available for public inspection in the above office during regular business hours.

FOR FURTHER INFORMATION CONTACT: Contact William F. Newell, Chief, Order Operations Branch, Dairy Programs, (202) 690–2375, FAX: (202) 720–2454.

SUPPLEMENTARY INFORMATION:

Title: Report Forms Under Federal Milk Orders (From Milk Handlers and Milk Marketing Cooperatives).

OMB Number: 0581–0032.

Expiration Date of Approval: September 30, 2007.

Type of Request: Extension and revision of a currently approved information collection.

Abstract: Federal milk marketing order regulations authorized under the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601–674), require milk handlers to report in detail the receipts and utilization of milk and milk products handled at each of their plants that are regulated by a Federal order. The data are needed to administer the classified pricing system and related requirements of each Federal order.

A Federal milk marketing order (hereinafter, Order) is a regulation issued by the Secretary of Agriculture that places certain requirements on the handling of milk in the area it covers. Each Order is established under the authority of the Act. The Order requires that handlers of milk for a marketing area pay not less than certain minimum class prices according to how the milk is used. These prices are established under each Order after a public hearing at which evidence is received on the supply and demand conditions for milk in the market. An Order requires that payments for milk be pooled and paid to individual farmers or cooperative associations of farmers on the basis of a uniform or average price. Thus, all eligible farmers (producers) share in the market wide use-values of milk by regulated handlers.

Milk Orders help ensure adequate supplies of milk and dairy products for consumers and adequate returns to producers.

The Orders also provide for the public dissemination of market statistics and other information for the benefit of producers, handlers, and consumers.

Formal rulemaking amendments to the Orders must be approved in referenda conducted by the Secretary.

During 2006, 52,725 dairy farmers delivered over 120 billion pounds of milk to handlers regulated under the milk orders. This volume represents 67 percent of all milk marketed in the U.S. and 68 percent of the milk of bottling quality (Grade A) sold in the country. The value of this milk delivered to Federal milk order handlers at minimum order blend prices was nearly $16.0 billion. Producer deliveries of milk used in Class I products (mainly fluid milk products) totaled 45 billion pounds—38 percent of total producer deliveries. More than 239 million Americans reside in Federal milk order marketing areas—80 percent of the total U.S. population.

Each Order is administered by a market administrator who is an agent of the Secretary of Agriculture. The market administrator is authorized to levy assessments on regulated handlers to carry out the market administrator's duties and responsibilities under the Orders. Additional duties of the market administrators are to prescribe reports required of each handler, to assure that handlers properly account for milk and milk products, and to assure that such handlers pay producers and associations of producers according to the provisions of the Order. The market administrator employs a staff that verifies handlers' reports by examining records to determine that the required payments are made to producers. Most reports required from handlers are submitted monthly to the market administrator.

The forms used by the market administrators are required by the respective Orders that are authorized by the Act. The forms are used to establish: The quantity of milk received by handlers, the pooling status of the handler, the class-use of the milk used by the handler, and the butterfat content and amounts of other components of the milk.

The forms covered under this information collection require the minimum information necessary to effectively carry out the requirements of the Orders, and their use is necessary to fulfill the intent of the Act as expressed in the Orders and in the rules and regulations issued under the Orders.

The information collected is used only by authorized employees of the market administrator and authorized representatives of the USDA, including AMS Dairy Programs' headquarters staff.

Estimate of Burden: Public reporting burden for this collection of information is estimated to average 1.07 hours per response.

Respondents: Milk handlers and milk marketing cooperatives.

Estimated Number of Respondents: 740.

Estimated Number of Responses: 20,565.

Estimated Number of Responses per Respondent: 28.

Estimated Total Annual Burden on Respondents: 21,818 hours.

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 become a matter of public record.

Dated: March 29, 2007.

Lloyd C. Day,

Administrator, Agricultural Marketing Service.

[FR Doc. E7–6248 Filed 4–3–07; 8:45 am]

BILLING CODE 3410–02–P

DEPARTMENT OF AGRICULTURE

Food Safety and Inspection Service

[Docket No. FSIS–2007–0012]

Risk-Based Inspection System

AGENCY: Food Safety and Inspection Service, USDA.

ACTION: Notice of public meetings on risk-based inspection

SUMMARY: The Food Safety and Inspection (FSIS) will hold a series of public meetings on specific topics relating to risk-based inspection in processing. The first meeting will focus on the algorithm that the Agency intends to use to compute risk-based inspection levels for processing establishments. A second meeting will address the issue of attributing illness to food. Production volume will be discussed at the third meeting, and industry data will be the focus of the fourth meeting. The expert elicitation process will be discussed at the fifth meeting.

DATES: FSIS will hold the meetings on the following dates:

Monday, April 2, 2007 from 9 a.m. to 1 p.m. The first meeting will focus on the algorithm the Agency intends to use to compute risk-based inspection levels for processing establishments.

Thursday, April 5, 2007 from 8:30 a.m. to 4 p.m. This meeting will discuss the issue of attributing illness to food.

Wednesday, April 25, 2007 from 9 a.m. to 1 p.m. Production volume will be discussed at the third meeting.

Monday, April 30, 2007 from 9 a.m. to 1 p.m. The topic of industry data is the focus of the fourth meeting. A technical meeting on the expert elicitation process is also planned as the fifth meeting. The date of this meeting will be announced at a later time. Any changes in meeting dates or times will be posted on the FSIS Web site at *http://www.fsis.usda.gov*.

ADDRESSES: The meetings will be held in Room 244 at George Mason University, 3401 N. Fairfax Drive, Arlington, VA 22201. Directions to the site, the agenda, and other meeting materials will be posted on the FSIS Web site at *http://www.fsis.usda.gov*.

All meetings will be accessible through conference call. Specific information concerning connections and the telephone number will also be posted on the FSIS Web site. Members of the public should pre-register for the meetings (see Background). Online registration information is also located on the Web site.

FSIS welcomes comments on the topics to be discussed at the public meetings. An issue paper concerning the respective topics will be posted on the FSIS Web site, *http://www.fsis.usda.gov*, a week prior to each meeting, with the exception of the meeting on attribution. Comments may be submitted on the meeting topics by any of the following methods for 30 days from the date of completion of each public meeting:

- Electronic mail: An e-mail box has been established specifically for comments for RBI. Comments can be submitted to: *riskbasedinspection@fsis.usda.gov*.
- *Mail, including floppy disks or CD–ROMs:* Send to: Ellyn Blumberg, USDA, FSIS, Aerospace Building, 3rd floor, room 405, 14th and Independence Avenue, SW., Washington, DC 20250.
- *Hand or courier-delivered items:* Deliver to: Ellyn Blumberg at 901 D Street, SW., Washington, DC 20024. Have security guard call (202) 690–6520 in order to hand deliver items.
- *Facsimile: Fax comments to:* (202) 690–6519.

All submissions received must include the Agency name and docket number FSIS–2007–0012 and meeting topic. The comments also will be posted on the Agency's Web site at *http://www.fsis.usda.gov*.

FOR FURTHER INFORMATION CONTACT: Sally Fernandez for meeting information at (202) 690–6524, Fax (202) 690–6519, or e-mail *sally.fernandez@fsis.usda.gov*. Keith Payne for technical information at (202) 690–6522 or e-mail at *keith.payne@fsis.usda.gov*. Persons requiring a sign language interpreter or other special accommodations should notify the Agency contacts no later than two weeks before the meeting, at the numbers above or by e-mail.

SUPPLEMENTARY INFORMATION:

Background

FSIS is the public health regulatory agency in the U.S. Department of Agriculture (USDA) responsible for ensuring that the nation's commercial supply of meat, poultry, and egg products is safe, wholesome, and correctly labeled and packaged.

To better address the food safety and public health challenges it faces, FSIS is working to make its inspection system more risk-based and to continue to implement science-based policies. Although the Agency acknowledges that some types of meat and poultry products pose greater health risks than others, and some establishments control risks better than others, under the current system of processing inspection, a Consumer Safety Inspector visits every plant at least once every shift to perform a variety of verification procedures scheduled by the Performance Based Inspection System (PBIS.) PBIS schedules inspection procedures the same way in all processing plants, regardless of the particular food safety hazard associated with the products produced or processes performed at one plant versus another.

In July 2004, the Agency outlined the basic features of a predictive model that would permit FSIS to improve resource allocation by considering the inherent risks and risk control effectiveness of the meat and poultry establishments under Federal inspection. Since that time, FSIS has continued to develop and refine these ideas. In November 2005, FSIS addressed the National Advisory Committee on Meat and Poultry Inspection (NAMCPI) on Agency progress toward a Risk-Based Inspection System (RBIS). In May 2006, the Agency again addressed NAMCPI—this time on ideas the Agency has on measuring risk control effectiveness for RBI.

Reductions in the number of illnesses attributed to the consumption of adulterated meat and poultry products can be achieved by placing greater inspection and verification emphasis on establishments whose processes, owing to the nature and volume of their production, require greater control of the risks. FSIS believes that it can improve public health by focusing its efforts on processing establishments that produce products presenting high inherent risk and that are less effective in controlling risks. At the same time, FSIS can focus less on processing establishments that produce products that present low inherent risk and that exercise effective risk control. In both cases, establishments will continue to be inspected on a per shift basis, although the intensity of inspection will vary, depending on risk factors.

In October 2006, FSIS held a public meeting to present ideas about how the Agency can develop these measures for federally-inspected meat and poultry processing establishments and to accept stakeholder input.

This series of technical meetings that the Agency is announcing will address various dimensions of RBI and protecting public health, and FSIS is seeking input from all stakeholders on these matters. Prior to each meeting, FSIS will post on its Web site an issue

paper on its current thinking concerning the respective topic or other relevant materials. At the meeting relating to attributing illness to food, the agency will invite experts to provide information and views on the definitions of attribution as well as state of the art methods in collecting attribution data. Each meeting will be moderated to ensure that all participants have ample opportunity to present their views. A transcript of the meetings will be taken and made available on the FSIS Web site, *http://www.fsis.usda.gov*.

All comments received in response to this notice will be considered part of the public record.

Members of the public should pre-register for the meeting. Online registration information is located at *http://www.fsis.usda.gov.*

Additional Public Notification

Public awareness of all segments of rulemaking and policy development is important. Consequently, in an effort to ensure that minorities, women and persons with disabilities are aware of this notice, FSIS will announce it online through the FSIS Web page located at *http://www.fsis.usda.gov/regulations/2007_Notices_Index/*. FSIS will also make copies of this **Federal Register** publication available through the FSIS Constituent Update, which is used to provide information regarding FSIS policies, procedures, regulations, **Federal Register** notices, FSIS public meetings, recalls, and other types of information that could affect or would be of interests to constituents and stakeholders. The update is communicated via Listserv, a free electronic mail subscription service for industry, trade and farm groups, consumer interest groups, allied health professionals, and other individuals who have asked to be included. The update is available on the FSIS Web page. Through the Listserv and Web page, FSIS is able to provide information to a much broader and more diverse audience. In addition, FSIS offers an e-mail subscription service which provides automatic and customized access to selected food safety news and information. This service is available at *http://www.fsis.usda.gov/news_and_events/email_subscription/*. Options range from recalls to export information to regulations, directives and notices. Customers can add or delete subscriptions themselves and have the option to password protect their account.

David P. Goldman,

Acting Administrator.

[FR Doc. 07–1662 Filed 3–30–07; 3:56 pm]

BILLING CODE 3410–DM–P

DEPARTMENT OF COMMERCE

Economics and Statistics Administration

Bureau of Economic Analysis Advisory Committee

AGENCY: Bureau of Economic Analysis, Economics and Statistics Administration, Department of Commerce.

ACTION: Notice of Public Meeting.

SUMMARY: Pursuant to the Federal Advisory Committee Act (Pub. L. 92–463 as amended by Pub. L. 94–409, Pub. L. 96–523, Pub. L. 97–375 and Pub. L. 105–153), we are announcing a meeting of the Bureau of Economic Analysis Advisory Committee. The meeting's agenda focuses on the various aspects involved with the measurement of health care in the national economic accounts.

DATES: Friday, May 4, 2007, the meeting will begin at 9 a.m. and adjourn at approximately 3:30 p.m.

ADDRESSES: The meeting will take place at the Bureau of Economic Analysis at 1441 L St., NW., Washington, DC.

FOR FURTHER INFORMATION CONTACT: Dorothy Andrake, Communications Division Chief, Bureau of Economic Analysis, U.S. Department of Commerce, Washington, DC 20230; *telephone number:* (202) 606–9630.

Public Participation: This meeting is open to the public. Because of security procedures, anyone planning to attend the meeting must contact Dorothy Andrake of BEA at (202) 606–9630 in advance. The meeting is physically accessible to people with disabilities. Requests for foreign language interpretation or other auxiliary aids should be directed to Dorothy Andrake at (202) 606–9630.

SUPPLEMENTARY INFORMATION: The Committee was established September 2, 1999. The Committee advises the Director of BEA on matters related to the development and improvement of BEA's national, regional, industry, and international economic accounts, especially in areas of new and rapidly growing economic activities arising from innovative and advancing technologies, and provides recommendations from the perspectives of the economics profession, business, and government. This will be the Committee's fifteenth meeting.

Dated: March 26, 2007.

J. Steven Landefeld,

Director, Bureau of Economic Analysis.

[FR Doc. E7–6212 Filed 4–3–07; 8:45 am]

BILLING CODE 3510–06–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

Papahānaumokuākea Marine National Monument, Hawai'i; Monument Management Plan

AGENCIES: U.S. Fish and Wildlife Service (FWS), Interior; National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; Preparation of a management plan, and environmental assessment.

SUMMARY: This notice advises the public that NOAA, FWS, and the Department of Land and Natural Resources, State of Hawai'i (DLNR) intend to prepare a Monument Management Plan (Monument Plan) and associated environmental assessment for the Papahānaumokuākea Marine National Monument in the Northwestern Hawaiian Islands and surrounding marine areas. The Monument Plan will modify NOAA's existing Northwestern Hawaiian Islands Proposed National Marine Sanctuary Draft Management Plan, and incorporate FWS refuge comprehensive conservation planning (CCP) requirements, DLNR planning needs, and other elements to reflect the area's new status as a national monument.

DATES: Any written comments must be received by June 4, 2007.

ADDRESSES: Send written comments to Don Palawski, Monument Plan Coordinator, U.S. Fish and Wildlife Service, 300 Ala Moana Boulevard, Box 50167, Honolulu, HI 96850–5000; or via e-mail to *PMNM_MMP_Comments@fws.gov*.

FOR FURTHER INFORMATION CONTACT: Don Palawski, Monument Plan Coordinator, U.S. Fish and Wildlife Service, 300 Ala Moana Boulevard, Box 50167, Honolulu, HI 96850–5000; phone (808) 792–9560, or fax (808) 792–9585.

SUPPLEMENTARY INFORMATION: On June 15, 2006, President George W. Bush

established the Northwestern Hawaiian Islands Marine National Monument by issuing Presidential Proclamation 8031 (Proclamation) (71 FR 36443, June 26, 2006) under the authority of the Antiquities Act (16 U.S.C. 431) (Act). On February 28, 2007, President Bush amended the Proclamation to give it a Native Hawaiian name, chosen by Native Hawaiians, that reflects Hawaiian language and culture. On March 2, 2007, the First Lady, Mrs. Laura Bush, presented the new name, Papahānaumokuākea Marine National Monument, to the public.

Proclamation 8031 reserves all lands and interests in lands owned or controlled by the Government of the United States in the Northwestern Hawaiian Islands (NWHI), including emergent and submerged lands and waters out to a distance of approximately 50 nautical miles (nmi) from the islands. The Monument is approximately 100 nmi wide and extends approximately 1,200 miles around coral islands, seamounts, banks, and shoals. The area includes the Northwestern Hawaiian Islands Coral Reef Ecosystem Reserve, the Midway Atoll National Wildlife Refuge/Battle of Midway National Memorial, the Hawaiian Islands National Wildlife Refuge, the Hawai'i State Seabird Sanctuary at Kure Atoll, and NWHI State Marine Refuge. The Secretaries of Commerce and the Interior, and the Governor of Hawai'i signed a Memorandum of Agreement on December 8, 2006, to jointly manage Federal and State lands and waters within the Monument as Co-Trustees, to collectively protect, conserve, and enhance Monument fish, plant, and wildlife habitats, including coral reefs and other marine and terrestrial resources.

During the last 5 years, as part of the National Marine Sanctuary designation process, NOAA actively sought input from Federal and State entities, Native Hawaiian leaders, the Northwestern Hawaiian Islands Coral Reef Ecosystem Reserve Advisory Council, and the public to develop a Draft Sanctuary Management Plan (available on the Internet at: *http://www.hawaiireef.noaa.gov*). More than 52,000 public comments were received during the sanctuary designation process. The Proclamation recognizes these efforts by directing the Secretary of Commerce, in consultation with the Secretary of the Interior and the State of Hawai'i, to modify, as appropriate, the draft Sanctuary Management Plan for management of the Monument. Another document relevant to Monument management, the Draft Interim Visitor Services Plan for the Midway Atoll National Wildlife Refuge, the Battle of Midway National Memorial, and the Northwestern Hawaiian Islands Marine National Monument's Midway Atoll Special Management Area, was distributed for public review in December 2006. Comments submitted during the Sanctuary designation process and comments received on Midway's Visitor Services Plan regarding issues that are subject to decision by the Co-Trustees (that is, not already decided by the President and memorialized in the Proclamation) will be considered when the agencies are determining the scope of the Monument Plan and during development of the Draft Monument Plan. Any additional comments at this stage should be focused on any new environmental issues identified as a result of new information or changed circumstances since the comment periods identified above. The Co-Trustees will develop co-management strategies and activities to meet the needs of FWS, NOAA, and DLNR in the Monument Plan.

The National Wildlife Refuge System Administration Act of 1966 (Refuge Administration Act), as amended by the National Wildlife Refuge System Improvement Act of 1997 (16 U.S.C. 668dd–668ee), requires the FWS to develop a comprehensive conservation plan (CCP) for each national wildlife refuge. The purpose in developing a CCP is to provide refuge managers with a 15-year strategy for achieving refuge purposes and contributing toward the mission of the National Wildlife Refuge System, consistent with sound principles of fish and wildlife management, conservation, legal mandates, and FWS policies. In addition to outlining broad management direction on conserving wildlife and their habitats, CCPs identify wildlife-dependent recreational opportunities available to the public. The State maintains its existing responsibility for managing State waters in the Monument, including the NWHI State Marine Refuge and Hawai'i State Seabird Sanctuary at Kure Atoll. NOAA maintains responsibility for the NWHI Coral Reef Ecosystem Reserve, included within the Monument, and has primary responsibility regarding the management of the marine areas of the Monument, in consultation with FWS.

It is the intent of the Co-Trustees to integrate agency planning and operational needs into a single Monument Plan. A draft Monument Plan will be distributed for public review and comment early in 2008. The Co-Trustees will also develop an environmental assessment in accordance with the requirements of the National Environmental Policy Act of 1969 (NEPA), as amended (42 U.S.C. 4321 et seq.); NEPA Regulations (40 CFR parts 1500–1508); other appropriate Federal laws and regulations; and agency policies and procedures for compliance with those regulations.

Public Availability of Comments

Before including your address, phone number, e-mail 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.

Agency Points of Contact

FWS: Barry Stieglitz, Monument Project Leader (USFWS); Hawaiian and Pacific Islands NWR Complex, 300 Ala Moana Boulevard, Box 50167, Honolulu, HI 96850–5000; phone (808) 792–9540.

NOAA: T. Aulani Wilhelm, Monument Superintendent (NOAA); 6600 Kalaniana'ole Highway, #300, Honolulu, HI 96825; phone (808) 397–2657.

State of Hawai'i: Athline Clark, Special Projects Manager, Department of Land and Natural Resources, Division of Aquatic Resources; 1151 Punchbowl Street, Room 330, Honolulu, HI 96813; phone (808) 587–0099.

Dated: March 28, 2007.

David J. Wesley,

Acting Regional Director, Fish and Wildlife Service, Region 1, Portland, Oregon.

Elizabeth Scheffler,

Chief Financial Officer, National Ocean Service, National Oceanic and Atmospheric Administration, Silver Spring, Maryland.

[FR Doc. 07–1652 Filed 4–3–07; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[I.D. 022807B]

Pre-assessment Workshop and Public Meeting for West Coast Canary Rockfish, Darkblotched Rockfish and Arrowtooth Flounder

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

ACTION: Notice of public meeting.

SUMMARY: NOAA Fisheries will hold a workshop to discuss the data and models that will be used in the upcoming stock assessments for canary rockfish, darkblotched rockfish and arrowtooth flounder.

DATES: The Pre-assessment Workshop for West Coast Canary Rockfish, Darkblotched Rockfish and Arrowtooth Flounder will be held Tuesday, April 24 through Wednesday, April 25, 2007. The workshop will meet each day from 8:30 a.m. through 4:30 p.m., or until business for the day is completed.

ADDRESSES: The Pre-Assessment Workshop for West Coast Canary Rockfish, Darkblotched Rockfish and Arrowtooth Flounder will be held at Pacific States Marine Fisheries Commission, 205 S.E. Spokane Street, Portland, Oregon 97202.

FOR FURTHER INFORMATION CONTACT: Ms. Stacey Miller, Northwest Fisheries Science Center (NWFSC); telephone: (206) 437–5670; or Dr. Jim Hastie, Northwest Fisheries Science Center (NWFSC); telephone: (206)860–3412.

SUPPLEMENTARY INFORMATION: This workshop is intended to initiate dialog between members of the fishing community, stock assessment authors, data managers, and interested members of the public prior to the finalization of the stock assessment model. The specific objectives of the workshop are to: (1) Discuss the data used in the canary rockfish, darkblotched rockfish and arrowtooth flounder stock assessments including details on collections methods, current observed trends, and how the data will be incorporated into the assessment models; (2) discuss the rationale for making assumptions in the models, especially when data are missing or insufficient; (3) identify anomalies in the data and provide possible explanations; and (4) identify data gaps and future research possibilities.

All participants are encouraged to pre-register for the workshop by contacting Ms. Stacey Miller, Northwest Fisheries Science Center (NWFSC) by phone at (206)437–5670 or by email at *Stacey.Miller@noaa.gov*.

Although non-emergency issues not contained in the meeting agenda may come before the workshop participants for discussion, those issues may not be the subject of formal workshop action during this meeting. Workshop action will be restricted to those issues specifically listed in this notice and any issues arising after publication of this notice that require emergency action under section 305c) of the Magnuson-Stevens Fishery Conservation and Management Act, provided the public has been notified of the workshop participants' intent to take final action to address the emergency.

Special Accommodations

This meeting is physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to Ms. Stacey Miller at (206) 437–5670 at least five days prior to the meeting date.

Dated: March 30, 2007.

Tracey L. Thompson,

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

[FR Doc. E7–6201 Filed 4–3–07; 8:45 am]

BILLING CODE 3510–22–S

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

National Estuarine Research Reserve System

AGENCY: Estuarine Reserves Division, Office of Ocean and Coastal Resource Management, National Ocean Service, National Oceanic and Atmospheric Administration, U.S. Department of Commerce.

ACTION: Notice of Public Comment Period for the Revised Management Plan for the Weeks Bay National Estuarine Research Reserve.

SUMMARY: Notice is hereby given that the Estuarine Reserves Division, Office of Ocean and Coastal Resource Management, National Ocean Service, National Oceanic and Atmospheric Administration (NOAA), U.S. Department of Commerce is announcing a thirty day public comment period on the revised Weeks Bay National Estuarine Research Reserve Management Plan which will begin on the day this announcement is published. Comments should be sent within the comment period in hard copy or e-mail to Matthew Chasse at *Matt.Chasse@noaa.gov* or NOAA's Estuarine Reserves Division, 1305 East-West Highway, N/ORM5, 10th floor, Silver Spring, MD 20910.

The Weeks Bay National Estuarine Research Reserve was designated in February 1986 pursuant to Section 315 of the Coastal Zone Management Act of 1972, as amended, 16 U.S.C. 1461. The reserve has been operating under a management plan approved in 1998. Pursuant to 15 CFR 921.33(c), a state must revise its management plan every five years. The submission of this plan fulfills this requirement and sets a course for successful implementation of the goals and objectives of the reserve. A boundary expansion, new facility and land acquisition plans, and updated programmatic objectives are notable revisions to the 1998 approved management plan.

Since the Weeks Bay National Estuarine Research Reserve was designated, it has been managed by the Alabama Department of Economic and Community Affairs. Since that time, state responsibility for the management of the reserve has been transferred to the Alabama Department of Conservation and Natural Resources (ADCNR), State Lands Division. A revised MOU between NOAA and the State of Alabama was approved to reflect these changes. Under ADCNR, the revised management plan outlines the administrative structure; the education, stewardship, and research goals of the reserve; and the plans for future land acquisition and facility development to support reserve operations.

Three hundred and thirty three (333) acres of state-owned coastal and submerged lands adjacent to the reserve are incorporated through the boundary amendment in the management plan revision. The expansion provides a broader and more representative diversity of wetland and water habitats into the reserve boundary. The new boundary and will provide areas for reserve related research and education programs. The tidal freshwater riverine, emergent and forested wetland communities protected through this expansion further enhance the Weeks Bay reserve as an appropriate and ecologically representative site for long-term research and education.

FOR FURTHER INFORMATION CONTACT: Matt Chasse at (301) 563–1198 or Laurie McGilvray at (301) 563–1158 of NOAA's National Ocean Service, Estuarine Reserves Division, 1305 East-West Highway, N/ORM5, 10th floor, Silver Spring, MD 20910. For copies of the Weeks Bay Management Plan revision, visit *http://www.sarpc.org.*

Dated: March 28, 2007.

David M. Kennedy,

Director, Office of Ocean and Coastal Resource Management, National Oceanic and Atmospheric Administration.

[FR Doc. E7–6195 Filed 4–3–07; 8:45 am]

BILLING CODE 3510–08–P

DEPARTMENT OF DEFENSE

Department of the Army

Preparation of an Environmental Impact Statement (EIS) for Stationing and Training of Increased Aviation Assets Within U.S. Army Alaska (USARAK)

AGENCY: Department of the Army, DoD.

ACTION: Notice of Intent.

SUMMARY: The Army intends to prepare an EIS to assess the potential environmental impacts associated with the stationing and training of increased numbers and types of aviation assets within Alaska. The proposed increase and reorganization will allow the Army to transition to a force that is capable of providing a broad range of integrated aviation training experience to the forces of USARAK and more aviation capabilities when the unit deploys to support operational missions abroad. Existing aviation units would potentially be reorganized and stationed at Fort Wainwright, Fort Richardson or other military installations to support the training of aviation assets on U.S. Army training lands in Alaska. The reorganized unit would be capable of providing first line air transport, air reconnaissance, and close air support. The new aviation unit would be built around the existing USARAK aviation fleet of 30 medium and heavy lift transport helicopters, and USARAK's 640 aviation personnel. To this the Army proposes to add helicopters capable of providing medical evacuation, air reconnaissance, close air support, and aviation attack capabilities. The proposed aviation unit, an Aviation Task Force or Combat Aviation Brigade (CAB), would potentially consist of up to 62 medium and heavy lift helicopters, 30 combat scout helicopter, 24 attack helicopters, and between 1,200 to 2,850 personnel. This proposed stationing and training of increased aviation assets involves construction of new facilities, execution of day-to-day support operations, and routine joint military training at nearby training lands and ranges. The action may have significant environmental impacts resulting from training and construction required as part of the proposed reorganization. Significant impacts resulting from this action may include impacts to air space, noise, and cultural resources. The EIS will analyze the impacts of the proposed action and a full range of reasonable alternatives upon Alaska's natural and man-made environments.

DATES: Written comments identifying potential impacts to be analyzed in the EIS must be received not later than May 4, 2007.

ADDRESSES: Written comments should be forwarded to Ms. Carrie McEnteer, Directorate of Public Works, Attention: IMPA–FWA–PWE (C. McEnteer), 1060 Gaffney Road #4500, Fort Wainwright, AK 99703–4500; fax: (907) 353–9867; e-mail: *carrie.mcenteer@us.army.mil.*

FOR FURTHER INFORMATION CONTACT: Mr. Robert Hall, Public Affairs Office, 724 Postal Service Loop Road, # 6000, Bldg. 600, Room B349, Fort Richardson, AK 99505–6000; telephone: (907) 384–2546, e-mail: *robert.hall33@us.army.mil*, or at Fort Wainwright, AK; telephone: (907) 353–6701.

SUPPLEMENTARY INFORMATION: To better support current and future national defense requirements, USARAK has restructured its two major military combat component units into modular force structures. These two components, the Stryker Brigade Combat Team (BCT) and Airborne BCT, have been reorganized to fit the Army's Modularity model as directed by the Army Campaign Plan. The new force structure offers a more flexible, sustainable, and rapidly deployable force, better to meet current and future defense requirements. The goal is for each BCT to be able to operate either independently or to integrate readily into a larger mission-tailored force capable of accomplishing a designated mission.

An essential element of USARAK combat capabilities is the development of modern war-fighting skills. Chief among these skills is the ability to integrate USARAK efforts with the vital support offered by modern Army aviation assets. These skills can only be mastered through frequent training with an aviation unit that is equipped with the full spectrum of aviation assets that are typically deployed to support a BCT during wartime. Such avaition units would provide infantry and light armored combat units first line air transport, air reconnaissance, and close air support.

While USARAK has historically supported unit training activities within Alaska with rotary-winged aircraft (helicopters), the types and numbers of current assets are not sufficient to provide the full range of integrated tactical training required by the modern BCT. To resolve this shortcoming, USARAK is proposing to reorganize its existing aviation assets (approximately 640 personnel and 30 medium and heavy lift helicopters) to become a front line aviaiton unit with an increased capacity that could range in size from an Aviation Task Force (approximately 1,200 personnel, 40–50 medium and heavy lift helicopters, and 30 combat scout helicopters) to a CAB (approximately 2,850 personnel, 60 medium and heavy lift helicopters, 30 combat scout helicopters, and 24 attack aviaiton helicopters). The new aviation unit would provide key aviation assets for operational deployment abroad, and would serve to enhance the training capability of USARAK's two BCTs by providing a local opportunity to conduct integrated training with multiple types of Army aviation assets.

In addition to consideration of a No Action Alternative (use of existing aviation assets and infrastructure to support USARAK BCT training with no increase to current integrated land-air training capability), three additional alternatives are proposed as possible scenarios for the reorganization of existing USARAK aviation assets. The alternatives vary by aviation unit size, aviation asset composition, and amount of facility construction. Alternatives include: (1) Expansion of Existing Aviation Units into an Aviation Task Force with Full Construction and Increased Training—convert existing USARAK aviation assets into an Aviation Task Force (approximately 1,200 personnel, station additional helicopters, build sufficient new infrastructure to support indoor storage of 100% of the Aviation Task Force's aviation inventory and conduct increased aviation training on existing Alaska military ranges; (2) Expansion of Existing Aviation Assets into a CAB with Partial Construction and Increased Training—convert existing USARAK aviation assets into a CAB, station additional helicopters, build sufficient new infrastructure to support indoor storage of 20% of the CABs aviation inventory and conduct increased aviation training on existing Alaska military ranges; and (3) Expansion of Existing Aviation Assets into a CAB with Full Construction and Increased Training—convert existing USARAK aviation assets into a CAB, station additional helicopters, build sufficient new infrastructure to support indoor storage of 100% of the CABs aviation inventory and conduct increased aviation training on existing Alaska military ranges. Additional potential alternative sites within Alaska will be evaluated based upon the purpose and need and criteria associated with the proposed action.

Scoping and Public Comment: Tribes, Federal, state, and local agencies and the public are invited to participate in the scoping process for the preparation of this EIS. Scoping meetings will be held in Fairbanks, Anchorage, and Delta

Junction, Alaska. The scoping process will help identify possible alternatives, potential environmental impacts, and key issues of concern to be analyzed in the EIS. Notification of the times and locations for the scoping meetings will be published in local newspapers.

Dated: March 26, 2007.

Addison D. Davis, IV,

Deputy Assistant Secretary of the Army (Environment, Safety, and Occupational Health).

[FR Doc. 07–1638 Filed 4–3–07; 8:45 am]

BILLING CODE 3710–08–M

DEPARTMENT OF EDUCATION

Notice of Proposed Information Collection Requests

AGENCY: Department of Education.

SUMMARY: The IC Clearance Official, Regulatory Information Management Services, Office of Management, invites comments on the proposed information collection requests as required by the Paperwork Reduction Act of 1995.

DATES: Interested persons are invited to submit comments on or before June 4, 2007.

SUPPLEMENTARY INFORMATION: Section 3506 of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35) requires that the Office of Management and Budget (OMB) provide interested Federal agencies and the public an early opportunity to comment on information collection requests. OMB may amend or waive the requirement for public consultation to the extent that public participation in the approval process would defeat the purpose of the information collection, violate State or Federal law, or substantially interfere with any agency's ability to perform its statutory obligations. The IC Clearance Official, Regulatory Information Management Services, Office of Management, publishes that notice containing proposed information collection requests prior to submission of these requests to OMB. Each proposed information collection, grouped by office, contains the following: (1) Type of review requested, e.g., new, revision, extension, existing or reinstatement; (2) Title; (3) Summary of the collection; (4) Description of the need for, and proposed use of, the information; (5) Respondents and frequency of collection; and (6) Reporting and/or Recordkeeping burden. OMB invites public comment.

The Department of Education 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.

Dated: March 30, 2007.

Angela C. Arrington,

IC Clearance Official, Regulatory Information Management Services, Office of Management.

Office of Postsecondary Education

Type of Review: Reinstatement.

Title: Robert C. Byrd Honors Scholarship Program Performance Report.

Frequency: Annually.

Affected Public: State, Local, or Tribal Gov't, SEAs or LEAs.

Reporting and Recordkeeping Hour Burden:

Responses: 57.

Burden Hours: 570.

Abstract: This information is required of State agencies that administer the Robert C. Byrd Honors Scholarship Program under Title IV, Part A, Subpart 6 of the Higher Education Act of 1965, as amended and administered under 34 CFR part 654. This information is used to monitor the compliance of the state educational agencies.

Requests for copies of the proposed information collection request may be accessed from *http://edicsweb.ed.gov*, by selecting the ''Browse Pending Collections'' link and by clicking on link number 3304. When you access the information collection, click on ''Download Attachments'' to view. Written requests for information should be addressed to U.S. Department of Education, 400 Maryland Avenue, SW., Potomac Center, 9th Floor, Washington, DC 20202–4700. Requests may also be electronically mailed to *ICDocketMgr@ed.gov* or faxed to 202–245–6623. Please specify the complete title of the information collection when making your request.

Comments regarding burden and/or the collection activity requirements should be electronically mailed to *ICDocketMgr@ed.gov*. Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339.

[FR Doc. E7–6279 Filed 4–3–07; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

[CFDA No. 84.330B]

Advanced Placement (AP) Test Fee Program

AGENCY: Office of Elementary and Secondary Education (OESE), Department of Education.

ACTION: Notice reopening the AP Test Fee fiscal year (FY) 2007 competition.

SUMMARY: On November 21, 2006, we published in the **Federal Register** (71 FR 67346) a notice inviting applications for the AP Test Fee FY 2007 competition. That notice established a January 5, 2007 deadline date for eligible applicants to apply for funding under this program. As a result of the applications we received, thirty-four awards were made on March 6, 2007.

In order to afford as many eligible applicants as possible an opportunity to receive funding under this program, we are reopening the AP Test Fee FY 2007 competition to eligible applicants that were not awarded funds on March 6, 2007. All information in the November 21, 2006 notice remains the same for this notice reopening the competition, except for the following updates to **DATES**.

DATES: Applications Available: April 4, 2007.

Deadline for Transmittal of Applications: April 18, 2007.

Note: Applications for grants under this program must be submitted electronically using the Governmentwide Grants.gov Apply site at *http://www.grants.gov*. For information about how to submit your application electronically, please refer to *Electronic Submission of Applications* in the November 21, 2006 notice (71 FR 67346–67348). We encourage eligible applicants to submit their applications as soon as possible to avoid any problems with filing electronic applications on the last day.

Deadline for Intergovernmental Review: May 4, 2007.

FOR FURTHER INFORMATION CONTACT: Ms. Lynyetta Johnson, U.S. Department of Education, 400 Maryland Avenue, SW., Washington, DC 20202–6200. Telephone: (202) 260–1990 or via Internet: *advancedplacementprogram@ed.gov*.

If you use a telecommunications device for the deaf (TDD), you may call the Federal Relay Service (FRS) at 1–800–877–8339. Individuals with disabilities may obtain this notice in an alternative format (e.g., Braille, large print, audiotape, or computer diskette) on request to the contact person listed in this section.

Electronic Access to This Document: You may view this document, as well as

other Department of Education documents published in the **Federal Register**, in text or Adobe Portable Document Format (PDF) on the Internet at the following site: *http://www.ed.gov/news/fedregister.*

To use PDF you must have Adobe Acrobat Reader, which is available free at this site. If you have questions about using PDF, call the U.S. Government Printing Office (GPO), toll free, at 1–888–293–6498; or in the Washington, DC, area at (202) 512–1530.

Note: The official version of this document is the document published in the **Federal Register**. Free Internet access to the official edition of the **Federal Register** and the Code of Federal Regulations is available on GPO Access at: *http://www.gpoaccess.gov/nara/index.html.*

Program Authority: 20 U.S.C. 6531–6537.

Dated: March 30, 2007.

Kerri L. Briggs,

Acting Assistant Secretary for Elementary and Secondary Education.

[FR Doc. E7–6255 Filed 4–3–07; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

Office of Postsecondary Education; Overview Information; Fund for the Improvement of Postsecondary Education—Special Focus Competition: European Union-United States Atlantis Program; Notice Inviting Applications for New Awards for Fiscal Year (FY) 2007

Catalog of Federal Domestic Assistance (CFDA) Number: 84.116J.

Dates: Applications Available: April 4, 2007.

Deadline for Transmittal of Applications: May 31, 2007.

Deadline for Intergovernmental Review: August 20, 2007.

Eligible Applicants: Institutions of higher education (IHEs) or combinations of IHEs and other public and private nonprofit institutions and agencies.

Estimated Available Funds: $2,500,000.

Estimated Range of Awards: $50,000–$102,000 for the first year only.

Estimated Average Size of Awards: $50,000 for the first year only and $408,000 for the four-year duration of a grant.

Maximum Award: We will reject any application that proposes a budget exceeding $200,000 for a single budget period of 12 months. The Assistant Secretary for Postsecondary Education may change the maximum amount through a notice published in the **Federal Register**.

Estimated Number of Awards: 14.

Note: The Department is not bound by any estimates in this notice.

Project Period: Up to 48 months.

Full Text of Announcement

I. Funding Opportunity Description

Purpose of Program: The purpose of this program is to provide grants or enter into cooperative agreements with eligible applicants to improve postsecondary education opportunities by developing and implementing undergraduate joint or dual degree programs or short-term exchange programs. The EU-U.S. Atlantis program is a revision of the European Union-United States Cooperation Program in Higher Education and Vocational Education and Training.

Priority: Under this competition, we are particularly interested in applications that address the following priority.

Invitational Priority: For FY 2007 this priority is an invitational priority. Under 34 CFR 75.105(c)(1) we do not give an application that meets this invitational priority a competitive or absolute preference over other applications. This priority is designed to support the formation of educational consortia of American and European institutions to support cooperation in the coordination of curricula, the exchange of students, and the opening of educational opportunities between the United States and the European Union. This priority relates to the purpose of the program to develop and implement undergraduate joint or dual degree programs or short-term exchange programs.

This invitational priority is established in cooperation with the European Union. These awards support only the participation of U.S. institutions and students in these consortia. European Union institutions participating in any consortium proposal responding to the invitational priority may apply, respectively, to the Directorate-General for Education and Culture (DG EAC), European Commission for funding under a separate but parallel EU competition.

Program Authority: 20 U.S.C. 1138–1138d.

Applicable Regulations: The Education Department General Administrative Regulations (EDGAR) in 34 CFR parts 74, 75, 77, 79, 80, 82, 84, 85, 86, 97, 98, and 99.

II. Award Information

Type of Award: Discretionary grants.

Estimated Available Funds: $2,500,000.

Estimated Range of Awards: $50,000–$102,000 for the first year only.

Estimated Average Size of Awards: $50,000 for the first year only and $408,000 for the four-year duration of a grant.

Maximum Award: We will reject any application that proposes a budget exceeding $200,000 for a single budget period of 12 months. The Assistant Secretary for Postsecondary Education may change the maximum amount through a notice published in the **Federal Register**.

Estimated Number of Awards: 14.

Note: The Department is not bound by any estimates in this notice.

Project Period: Up to 48 months.

III. Eligibility Information

1. *Eligible Applicants:* IHEs or combinations of IHEs and other public and private nonprofit institutions and agencies.

2. *Cost Sharing or Matching:* This program does not involve cost sharing or matching.

IV. Application and Submission Information

1. *Address to Request Application Package:* Frank Frankfort, Fund for the Improvement of Postsecondary Education, U.S. Department of Education, 1990 K Street, NW., 6th floor, Washington, DC 20006–8544. Telephone: (202) 502–7513.

If you use a telecommunications device for the deaf (TDD), you may call the Federal Relay Service (FRS) at 1–800–877–8339.

Individuals with disabilities may contact the Education Publications Center (ED Pubs), P.O. Box 1398, Jessup, MD 20794–1398. Telephone (toll free): 1–877–433–7827. FAX: (301) 470–1244. If you use a telecommunications device for the deaf (TDD), you may call (toll free): 1–877–576–7734.

You may also contact ED Pubs at its Web site: *http://www.ed.gov/pubs/edpubs.html* or you may contact ED Pubs at its e-mail address: *edpubs@inet.ed.gov.*

If you request an application from ED Pubs, be sure to identify this competition as follows: CFDA number 84.116J.

2. *Content and Form of Application Submission:* Requirements concerning the content of an application, together with the forms you must submit, are in the application package for this program.

Page Limit: The application narrative (Part III of the application) is where you, the applicant, address the selection criteria that reviewers use to evaluate

your application. You must limit Part III to the equivalent of no more than 20 pages (double spaced), using the following standards:

• A ''page'' is 8.5″ x 11″, on one side only, with 1″ margins at the top, bottom, and both sides.

• Double space (no more than three lines per vertical inch) all text in the application narrative, including titles, headings, footnotes, quotations, reference, and captions, as well as all text in charts, tables, figures, and graphs.

• Use a font that is either 12 point or larger or no smaller than 10 pitch (characters per inch).

• Use one of the following fonts: Times New Roman, Courier, Courier New, or Arial. Applications submitted in any other font (including Times Roman and Arial Narrow) will not be accepted.

The page limit does not apply to Part I, the cover sheet; Part II, the budget section, including the narrative budget justification; Part IV, the assurances and certifications; the one-page resumes, the bibliography, or the letters of commitment. However, you must include all of the application narrative in Part III.

We will reject your application if—

• You apply these standards and exceed the page limit; or

• You apply other standards and exceed the equivalent of the page limit.

3. *Submission Dates and Times: Applications Available*: April 4, 2007.

Deadline for Transmittal of Applications: May 31, 2007.

Applications for grants under this program must be submitted electronically using the Grants.gov Apply site (Grants.gov). For information (including dates and times) about how to submit your application electronically or by mail or hand delivery if you qualify for an exception to the electronic submission requirement, please refer to section IV. 6. Other Submission Requirements in this notice.

We do not consider an application that does not comply with the closing date requirements.

Individuals with disabilities who need an accommodation or auxiliary aid in connection with the application process should contact the person listed under **FOR FURTHER INFORMATION CONTACT**.

Deadline for Intergovernmental Review: August 20, 2007.

4. *Intergovernmental Review:* This program is subject to Executive Order 12372 and the regulations in 34 CFR part 79. Information about Intergovernmental Review of Federal Programs under Executive Order 12372 is in the application package for this program.

5. *Funding Restrictions:* We reference regulations outlining funding restrictions in the *Applicable Regulations* section of this notice.

6. *Other Submission Requirements:* Applications for grants under this competition must be submitted electronically unless you qualify for an exception to this requirement in accordance with the instructions in this section.

a. *Electronic Submission of Applications.* Applications for grants under the European Union-United States Atlantis Program, CFDA Number 84.116J must be submitted electronically using the Governmentwide Grants.gov Apply site at *http://www.Grants.gov* Through this site, you will be able to download a copy of the application package, complete it offline, and then upload and submit your application. You may not e-mail an electronic copy of a grant application to us.

We will reject your application if you submit it in paper format unless, as described elsewhere in this section, you qualify for one of the exceptions to the electronic submission requirement *and* submit, no later than two weeks before the application deadline date, a written statement to the Department that you qualify for one of these exceptions. Further information regarding calculation of the date that is two weeks before the application deadline date is provided later in this section under *Exception to Electronic Submission Requirement.*

You may access the electronic grant application for the European Union-United States Atlantis Program at *http://www.Grants.gov.* You must search for the downloadable application package for this program or competition by the CFDA number. Do not include the CFDA number's alpha suffix in your search (e.g., search for 84.326, not 84.326J).

Please note the following:

• When you enter the Grants.gov site, you will find information about submitting an application electronically through the site, as well as the hours of operation.

• Applications received by Grants.gov are date and time stamped. Your application must be fully uploaded and submitted, and must be date and time stamped by the Grants.gov system no later than 4:30 p.m., Washington, DC time, on the application deadline date. Except as otherwise noted in this section, we will not consider your application if it is date and time stamped by the grants.gov system later than 4:30 p.m., Washington, DC time, on the application deadline date. When we retrieve your application from Grants.gov, we will notify you if we are rejecting your application because it was date and time stamped by the Grants.gov system after 4:30 p.m., Washington, DC time, on the application deadline date.

• The amount of time it can take to upload an application will vary depending on a variety of factors including the size of the application and the speed of your Internet connection. Therefore, we strongly recommend that you do not wait until the application deadline date to begin the submission process through Grants.gov.

• You should review and follow the Education Submission Procedures for submitting an application through Grants.gov that are included in the application package for this competition to ensure that you submit your application in a timely manner to the Grants.gov system. You can also find the Education Submission Procedures pertaining to grants.gov at *http://e-Grants.ed.gov/help/GrantsgovSubmissionProcedures.pdf.*

• To submit your application via Grants.gov, you must complete all steps in the Grants.gov registration process (see *http://www.Grants.gov/applicants/get_registered.jsp*). These steps include (1) registering your organization, a multi-part process that includes registration with the Central Contractor Registry (CCR); (2) registering yourself as an Authorized Organization Representative (AOR); and (3) getting authorized as an AOR by your organization. Details on these steps are outlined in the Grants.gov 3-Step Registration Guide (see *http://www.grants.gov/section910/Grants.govRegistrationBrochure.pdf*). You also must provide on your application the same D–U–N–S Number used with this registration. Please note that the registration process may take five or more business days to complete, and you must have completed all registration steps to allow you to submit successfully an application via Grants.gov. In addition you will need to update your CCR registration on an annual basis. This may take three or more business days to complete.

• You will not receive additional point value because you submit your application in electronic format, nor will we penalize you if you qualify for an exception to the electronic submission requirement, as described elsewhere in this section, and submit your application in paper format.

• You must submit all documents electronically, including all information you typically provide on the following forms: Application for Federal Assistance (SF 424), the Department of Education Supplemental Information for SF 424, Budget Information—Non-Construction Programs (ED 524), and all necessary assurances and certifications. Please note that two of these forms—the SF 424 and the Department of Education Supplemental Information for SF 424—have replaced the ED 424 (Application for Federal Education Assistance).

• You must attach any narrative sections of your application as files in a .DOC (document), .RTF (rich text), or .PDF (Portable Document) format. If you upload a file type other than the three file types specified in this paragraph or submit a password-protected file, we will not review that material.

• Your electronic application must comply with any page-limit requirements described in this notice.

• After you electronically submit your application, you will receive from Grants.gov an automatic notification of receipt that contains a Grants.gov tracking number. (This notification indicates receipt by Grants.gov only, not receipt by the Department.) The Department then will retrieve your application from Grants.gov and send a second notification to you by e-mail. This second notification indicates that the Department has received your application and has assigned your application a PR/Award number (an ED-specified identifying number unique to your application).

• We may request that you provide us original signatures on forms at a later date.

Application Deadline Date Extension in Case of Technical Issues with the Grants.gov System: If you are experiencing problems submitting your application through Grants.gov, please contact the grants.gov Support Desk at 1–800–518–4726. You must obtain a Grants.gov Support Desk Case Number and must keep a record of it.

If you are prevented from electronically submitting your application on the application deadline date because of technical problems with the Grants.gov system, we will grant you an extension until 4:30 p.m., Washington, DC time, the following business day to enable you to transmit your application electronically or by hand delivery. You also may mail your application by following the mailing instructions described elsewhere in this notice.

If you submit an application after 4:30 p.m., Washington, DC time, on the application deadline date, please contact the person listed elsewhere in this notice under *For Further Information Contact* and provide an explanation of the technical problem you experienced with Grants.gov, along with the Grants.gov Support Desk Case Number. We will accept your application if we can confirm that a technical problem occurred with the Grants.gov system and that that problem affected your ability to submit your application by 4:30 p.m., Washington, DC time, on the application deadline date. The Department will contact you after a determination is made on whether your application will be accepted.

Note: The extensions to which we refer in this section apply only to the unavailability of, or technical problems with, the Grants.gov system. We will not grant you an extension if you failed to fully register to submit your application to Grants.gov before the application deadline date and time or if the technical problem you experienced is unrelated to the Grants.gov system.

Exception to Electronic Submission Requirement: You qualify for an exception to the electronic submission requirement, and may submit your application in paper format, if you are unable to submit an application through the Grants.gov system because—

• You do not have access to the Internet; or

• You do not have the capacity to upload large documents to the Grants.gov system; *and*

• No later than two weeks before the application deadline date (14 calendar days or, if the fourteenth calendar day before the application deadline date falls on a Federal holiday, the next business day following the Federal holiday), you mail or fax a written statement to the Department, explaining which of the two grounds for an exception prevent you from using the Internet to submit your application.

If you mail your written statement to the Department, it must be postmarked no later than two weeks before the application deadline date. If you fax your written statement to the Department, we must receive the faxed statement no later than two weeks before the application deadline date.

Address and mail or fax your statement to: Frank Frankfort, U.S. Department of Education, 1990 K Street, NW., room 6152, Washington, DC 20006–8544. FAX: (202) 502–7877.

Your paper application must be submitted in accordance with the mail or hand delivery instructions described in this notice.

b. *Submission of Paper Applications by Mail.* If you qualify for an exception to the electronic submission requirement, you may mail (through the U.S. Postal Service or a commercial carrier) your application to the Department. You must mail the original and two copies of your application, on or before the application deadline date, to the Department at the applicable following address:

By mail through the U.S. Postal Service: U.S. Department of Education, Application Control Center, Attention: (CFDA Number 84.116J), 400 Maryland Avenue, SW., Washington, DC 20202–4260; or

By mail through a commercial carrier: U.S. Department of Education, Application Control Center, Stop 4260, Attention: (CFDA Number 84.116J), 7100 Old Landover Road, Landover, MD 20785–1506.

Regardless of which address you use, you must show proof of mailing consisting of one of the following:

(1) A legibly dated U.S. Postal Service postmark.

(2) A legible mail receipt with the date of mailing stamped by the U.S. Postal Service.

(3) A dated shipping label, invoice, or receipt from a commercial carrier.

(4) Any other proof of mailing acceptable to the Secretary of the U.S. Department of Education.

If you mail your application through the U.S. Postal Service, we do not accept either of the following as proof of mailing:

(1) A private metered postmark.

(2) A mail receipt that is not dated by the U.S. Postal Service.

If your application is postmarked after the application deadline date, we will not consider your application.

Note: The U.S. Postal Service does not uniformly provide a dated postmark. Before relying on this method, you should check with your local post office.

c. *Submission of Paper Applications by Hand Delivery.* If you qualify for an exception to the electronic submission requirement, you (or a courier service) may deliver your paper application to the Department by hand. You must deliver the original and two copies of your application by hand, on or before the application deadline date, to the Department at the following address: U.S. Department of Education, Application Control Center, Attention: (CFDA Number 84.116J), 550 12th Street, SW., Room 7041, Potomac Center Plaza, Washington, DC 20202–4260. The Application Control Center accepts hand deliveries daily between 8 a.m. and 4:30 p.m., Washington, DC time, except Saturdays, Sundays, and Federal holidays.

Note for Mail or Hand Delivery of Paper Applications: If you mail or hand deliver your application to the Department—

(1) You must indicate on the envelope and—if not provided by the Department—in Item 11 of the SF 424 the CFDA number, including suffix letter, if any, of the competition under which you are submitting your application; and

(2) The Application Control Center will mail to you a notification of receipt of your grant application. If you do not receive this notification within 15 business days from the application deadline date, you should call the U.S. Department of Education Application Control Center at (202) 245–6288.

V. Application Review Information

Selection Criteria: The selection criteria for evaluating applications for this program are from 34 CFR 75.210 of EDGAR and are listed in the application package.

VI. Award Administration Information

1. *Award Notices:* If your application is successful, we notify your U.S. Representative and U.S. Senators and send you a Grant Award Notification (GAN). We may also notify you informally.

If your application is not evaluated or not selected for funding, we notify you.

2. *Administrative and National Policy Requirements:* We identify administrative and national policy requirements in the application package and reference these and other requirements in the *Applicable Regulations* section of this notice.

We reference the regulations outlining the terms and conditions of an award in the *Applicable Regulations* section of this notice and include these and other specific conditions in the GAN. The GAN also incorporates your approved application as part of your binding commitments under the grant.

3. *Reporting:* At the end of your project period, you must submit a final performance report, including financial information, as directed by the Secretary. If you receive a multi-year award, you must submit an annual performance report that provides the most current performance and financial expenditure information as specified by the Secretary in 34 CFR 75.118.

4. *Performance Measures:* The Fund for the Improvement of Postsecondary Education (FIPSE) program has developed two performance measures that are considered indicators of the success of the program as a whole: (1) The extent to which funded projects are being replicated (i.e., adopted or adapted by others); and (2) the manner in which projects are being institutionalized and continued after funding. However, different indicators will be used to assess the success of the European Union-United States Atlantis Program, specifically, (1) The percentage of students pursuing a joint or dual degree who persist from one academic year to the next (persistence); and (2) the percentage of students who graduate within the project's stated time for completing a joint or dual degree (graduation). If funded, you will be asked to collect and report data from your project on steps taken toward achieving the goals of persistence and graduation. Consequently, applicants are advised to include these two outcomes in conceptualizing the design, implementation, and evaluation of their proposed projects.

VII. Agency Contact

For Further Information Contact: Frank Frankfort, Fund for the Improvement of Postsecondary Education, European Union-United States Atlantis Program, 1990 K Street, NW., 6th floor, Washington, DC 20006–8544. Telephone: (202) 502–7513.

If you use a telecommunications device for the deaf (TDD), you may call the Federal Relay Service (FRS) at 1–800–877–8339.

Individuals with disabilities may obtain this document in an alternative format (e.g., Braille, large print, audiotape, or computer diskette) on request to the program contact person listed in this section.

VIII. Other Information

Electronic Access to This Document: You may view this document, as well as all other documents of this Department published in the **Federal Register**, in text or Adobe Portable Document Format (PDF) on the Internet at the following site: *http://www.ed.gov/news/fedregister.*

To use PDF you must have Adobe Acrobat Reader, which is available free at this site. If you have questions about using PDF, call the U.S. Government Printing Office (GPO), toll free, at 1–888–293–6498; or in the Washington, DC, area at (202) 512–1530.

Note: The official version of this document is the document published in the **Federal Register**. Free Internet access to the official edition of the **Federal Register** and the Code of Federal Regulations is available on GPO Access at: *http://www.gpoaccess.gov/nara/index.html.*

Dated: March 30, 2007.

James F. Manning,

Delegated the Authority of Assistant Secretary for Postsecondary Education.

[FR Doc. E7–6261 Filed 4–3–07; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

Office of International Regimes and Agreements; Proposed Subsequent Arrangement

AGENCY: Department of Energy.

ACTION: Notice of Proposed Subsequent Arrangement.

SUMMARY: This notice is being issued under the authority of Section 131 of the Atomic Energy Act of 1954, as amended (42 U.S.C. 2160). The Department is providing notice of a proposed ''subsequent arrangement'' under the Agreement for Cooperation in the Peaceful Uses of Nuclear Energy between the United States and Argentina and the Agreement for Cooperation in the Peaceful Uses of Nuclear Energy between the United States and Brazil.

This subsequent arrangement concerns the retransfer of two fission counters from the Instrumentation and Control Department, National Atomic Energy Commission, Argentina, to the IPEN/MB/01 Research Reactor, San Pablo, Brazil. The fission counters each contain .01 g U235. IPEN/MB/01 Research Reactor is authorized to receive nuclear material pursuant to the U.S.-Brazil Agreement for Cooperation on Peaceful Uses of Nuclear Energy.

In accordance with Section 131 of the Atomic Energy Act of 1954, as amended, we have determined that this subsequent arrangement will not be inimical to the common defense and security.

This subsequent arrangement will take effect no sooner than 15 days after the date of publication of this notice.

Dated: March 29, 2007.

For the Department of Energy.

Richard S. Goorevich,

Director, Office of International Regimes and Agreements.

[FR Doc. 07–1666 Filed 4–3–07; 8:45 am]

BILLING CODE 6450–01–M

DEPARTMENT OF ENERGY

Office of International Regimes and Agreements; Proposed Subsequent Arrangement

AGENCY: Department of Energy.

ACTION: Notice of Proposed Subsequent Arrangement.

SUMMARY: This notice is being issued under the authority of Section 131 of the Atomic Energy Act of 1954, as amended (42 U.S.C. 2160). The Department is providing notice of a proposed ''subsequent arrangement'' under the

Agreement for Cooperation between the Government of the United States of America and the Republic of Korea Concerning Civil Uses of Atomic Energy, signed November 24, 1972, as amended.

This subsequent arrangement concerns the renewal of the 2002 Joint Determination by the Government of the United States of America and the Government of the Republic of Korea pursuant to Article VIII(C) of that Agreement. This arrangement reaffirms that the provisions of Article XI of the Joint Determination may be effectively applied for the alteration in form or content of U.S.-origin nuclear material contained in irradiated nuclear fuels from pressurized water reactors, CANDU reactors, a research reactor at the Post Irradiation Examination Facility (PIEF), the Irradiated Material Examination Facility (IMEF), the DUPIC Fuel Fabrications Facility (DFDF), and identified analytical laboratories at the Headquarters of the Korea Atomic Energy Research Institute, in accordance with the plan contained in KAERI/AR–765/2007, dated January 30, 2007, and KAERI/AR–766/2007, dated January 31, 2007. Any activities additional to the plan or changes in the equipment in the PIEF, IMEF, or the DFDF will be reviewed by both parties to ensure the general consistency with the scope and objectives of the Joint Determination. Reference is made to the Joint Determination signed by the Government of the United States of America and the Government of the Republic of Korea on March 29, 1996, on April 8, 1999, and on January 29, 2002, covering similar activities at the PIEF, the IMEF, and the DFDF. These facilities are found acceptable to both parties pursuant to Article VIII(C) of the Agreement for the sole purpose of alteration in form or content of irradiated fuel elements for post-irradiation examination and for research, development and manufacture of DUPIC fuel powders, pellets and elements for the period ending March 31, 2012.

In accordance with Section 131 of the Atomic Energy Act of 1954, as amended, we have determined that this subsequent arrangement will not be inimical to the common defense and security.

This subsequent arrangement will take effect no sooner than 15 days after the date of publication of this notice.

Dated: March 29, 2007.

For the Department of Energy.

Richard Goorevich,

Director, Office of International Regimes and Agreements.

[FR Doc. E7–6280 Filed 4–3–07; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Office of Energy Efficiency and Renewable Energy

State Energy Advisory Board

AGENCY: Department of Energy, Office of Energy Efficiency and Renewable Energy.

ACTION: Notice of Open Teleconference.

SUMMARY: This notice announces a teleconference of the State Energy Advisory Board (STEAB). The Federal Advisory Committee Act (Pub. L. 92–463; 86 Stat. 770) requires that public notice of these teleconferences be announced in the **Federal Register**.

DATES: April 19, 2007, 2 p.m. to 3 p.m. EST.

FOR FURTHER INFORMATION CONTACT: Gary Burch, STEAB Designated Federal Officer, Assistant Manager, Intergovernmental Projects & Outreach, Golden Field Office, U.S. Department of Energy, 1617 Cole Boulevard, Golden, CO 80401, Telephone 303/275–4801.

SUPPLEMENTARY INFORMATION: *Purpose of the Board:* To make recommendations to the Assistant Secretary for Energy Efficiency and Renewable Energy regarding goals and objectives, programmatic and administrative policies, and to otherwise carry out the Board's responsibilities as designated in the State Energy Efficiency Programs Improvement Act of 1990 (Pub. L. 101–440).

Tentative Agenda: Update members on routine business matters and action items generated during the March 2007, full-Board meeting in Washington, DC.

Public Participation: The teleconference is open to the public. Written statements may be filed with the Board either before or after the meeting. Members of the public who wish to make oral statements pertaining to agenda items should contact Gary Burch at the address or telephone number listed above. Requests to make oral comments must be received five days prior to the conference call; reasonable provision will be made to include requested topic(s) on the agenda. The Chair of the Board is empowered to conduct the call in a fashion that will facilitate the orderly conduct of business.

Notes: The notes of the teleconference will be available for public review and copying within 60 days at the Freedom of Information Public Reading Room, 1E–190, Forrestal Building, 1000 Independence Avenue, SW., Washington, DC, between 9 a.m. and 4 p.m., Monday through Friday, except Federal holidays. The notes will also be made available for downloading on the STEAB Web site, *http://www.steab.org*, within 60 days.

Issued at Washington, DC, on March 29, 2007.

Rachel Samuel,

Deputy Advisory Committee Management Officer.

[FR Doc. E7–6232 Filed 4–3–07; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Energy Information Administration

Agency Information Collection Activities: Proposed Collection; Comment Request

AGENCY: Energy Information Administration (EIA), Department of Energy (DOE).

ACTION: Agency information collection activities: proposed collection; comment request.

SUMMARY: The EIA is soliciting comments on the proposed revisions and a three-year extension to the Forms:

EIA–411, ''Coordinated Bulk Power Supply Program Report,''

EIA–826, ''Monthly Electric Sales and Revenue with State Distributions Report,''

EIA–860M, ''Monthly Update to the Annual Electric Generator Report,''

EIA–860, ''Annual Electric Generator Report,''

EIA–861, ''Annual Electric Power Industry Report,'' and

EIA–923, ''Power Plant Operations Report.''

Specifically, the EIA is soliciting comments on the following actions:

• First, merging the existing Form EIA–906 ''Power Plant Report,'' Form EIA–920, ''Combined Heat and Power Plant Report,'' and Form EIA–423, ''Monthly Cost and Quality of Fuels for Electric Plants,'' as well as transferring operational information on Schedules 3A (excluding items 7 and 8), 3B, 4A, 4D (items 3, 6, and 7), 6A, and 8A from the Form EIA–767, ''Steam-Electric Plant Operation and Design Report,'' to the proposed new Form EIA–923 ''Power Plant Operations Report,'' to be authorized for three years.

• Second, companies currently reporting on FERC Form–423, ''Monthly

Report of Cost and Quality of Fuel for Electric Plants,'' would be required to report cost and quality of fuel information on Form EIA–923.

• Third, transferring the static information collected on Form EIA–767, ''Steam-Electric Plant Operation and Design Report,'' from Schedules 2, 4B, 4C, 4D (except items 3, 6 and 7), 4E, 5 (items 3 and 4) 6B, 7, 8B, and 9 to the Form EIA–860, ''Annual Electric Generator Report.''

• Fourth, discontinuing Form EIA–767, ''Steam-Electric Plant Operation and Design Report,'' Form EIA–423, ''Monthly Cost and Quality of Fuels for Electric Plants,'' Form EIA–906, ''Power Plant Report,'' and Form EIA–920, ''Combined Heat and Power Plant Report.''

• Fifth, changing the current provisions regarding confidentiality of information reported on the electric power surveys.

DATES: Comments must be filed by June 4, 2007. If you anticipate difficulty in submitting comments within that period, contact the person listed below as soon as possible.

ADDRESSES: Send comments to Mr. Jorge Luna-Camara. To ensure receipt of the comments by the due date, submission by FAX (202–287–1946) or e-mail Mr. Luna-Camara at *Jorge.Luna-Camara@eia.doe.gov* is recommended. The mailing address is Energy Information Administration, Electric Power Division, EI–53, Forrestal Building, U.S. Department of Energy, Washington, DC 20585. Alternatively, Mr. Jorge Luna-Camara may be contacted by telephone at 202–287–1753.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of any forms and instructions should be directed to Mr. Jorge Luna-Camara at the address listed above. To review the proposed forms and instructions, please visit: *http://www.eia.doe.gov/cneaf/electricity/page/fednotice/elect_2008.html.*

SUPPLEMENTARY INFORMATION:

I. Background
II. Current Actions
III. Request for Comments

I. Background

The Federal Energy Administration Act of 1974 (Pub. L. 93–275, 15 U.S.C. 761 *et seq.*) and the DOE Organization Act (Pub. L. 95–91, 42 U.S.C. 7101 *et seq.*) require the EIA to carry out a centralized, comprehensive, and unified energy information program. This program collects, evaluates, assembles, analyzes, and disseminates information on energy resource reserves, production, demand, technology, and related economic and statistical information. This information is used to assess the adequacy of energy resources to meet near and longer term domestic demands.

The EIA, as part of its effort to comply with the Paperwork Reduction Act of 1995 (Pub. L. 104–13, 44 U.S.C. 3501 *et seq.*), provides the general public and other Federal agencies with opportunities to comment on collections of energy information conducted by or in conjunction with the EIA. Any comments received help the EIA to prepare data requests that maximize the utility of the information collected, and to assess the impact of collection requirements on the public. Also, the EIA will later seek approval by the Office of Management and Budget (OMB) under Section 3507(a) of the Paperwork Reduction Act of 1995.

The EIA collects information about the electric power industry for use by government and private sector analysts. The survey information is disseminated in a variety of electronic products and files. For details on the EIA electric power information program, please visit the electricity page of the EIA Internet site at *http://www.eia.doe.gov/fuelelectric.html.*

The EIA has completed an extensive review and update of the electric power survey collection instruments. The result of the update reflects input from the electric power industry, other industry users of the data, government agencies, consumer groups, and private sector analysts. Along with the form changes and proposed mergers, the EIA is proposing a revision to the commercially sensitive data elements that will be protected from release. These issues are explained below.

This **Federal Register** notice solicits comments on proposed changes to five surveys and two proposed merger concepts. The first merger is for the Form EIA–906 ''Power Plant Report,'' Form EIA–920, ''Combined Heat and Power Plant Report,'' and Form EIA–423, ''Monthly Cost and Quality of Fuels for Electric Plants,'' to be merged into the new Form EIA–923, ''Power Plant Operations Report.'' Also, companies currently reporting on FERC Form–423, ''Monthly Report of Cost and Quality of Fuel for Electric Plants,'' would be required to file on Form EIA–923 information on cost and quality of fuels. The proposed Form EIA–923 combines receipts, consumption and fossil fuel stock information for all electric power producers on one form. Currently the data are collected on different forms, which are due at different times. By merging the forms, the information can be collected and checked at the same time. For example, the previous month's ending stocks, plus receipts, minus consumption must equal the current month's ending stocks. The consolidation into one form is expected to facilitate reporting and respondents will be able to review and correct their data prior to submission, thereby improving the quality and timeliness of the data. Also combining information collected by both EIA and the Federal Energy Regulatory Commission on a single form has the potential to increase the overall efficiency of the Federal program to collect monthly fuel information as well as improve the utility of the resulting information products.

In addition, it is proposed that the merged Form EIA–923 will also collect fuel consumption information at the boiler level for plants with steam turbines of 10 megawatts or greater capacity that burn fossil or organic fuels (excluding steam turbines whose source of steam is from nuclear, geothermal or solar resources), which was formerly collected on the Form EIA–767. This will maintain the existing data series for use in analysis and reduce the burden on the monthly respondents, as they will only have to provide these data once, rather than on both the Form EIA–767 and either Form EIA–906 or Form EIA–920. In addition, the other operational information collected on the Form EIA–767 will be transferred to the new Form EIA–923.

The second merger is of the Form EIA–860, ''Annual Electric Generator Report,'' and the static information from the Form EIA–767, ''Steam-Electric Plant Operation and Design Report.'' This merger would allow the respondents to report all of their static plant level information on one form (EIA–860), thereby reducing the level of overlap in filing multiple forms and making their submissions more consistent. With the mergers noted above, EIA will be able to eliminate four existing electric power survey forms.

Please refer to the proposed forms and instructions for more information about the purpose, who must report, when to report, where to submit, the elements to be reported, detailed instructions, provisions for confidentiality, and uses (including possible non-statistical uses) of the information. For instructions on obtaining materials, see the **FOR FURTHER INFORMATION CONTACT** section.

II. Current Actions

The EIA proposes the following changes:

Form EIA–411, ''Coordinated Bulk Power Supply Program Report''

The EIA proposes the following changes to the form:

• Eliminate Schedule 2, Capacity for Existing Generators in Reporting Year, as this information will be subsumed in Schedule 3.

• Modify Schedule 3. Historical and Projected Demand and Capacity. The categories will explain the differences between net capacity reported to EIA by its respondents on the Form EIA–860 and the Planned Capacity Resource data reported by the North American Electric Reliability Corporation (NERC) on Schedule 3, Reconciliation between Total Generation Regional Capacity and Planned Regional Capacity Resources (summer, winter).

It is proposed that reporting on Form EIA–411 become mandatory for all electric generators who are connected to the electricity grid. Over time, as utilities have sold their generating assets, the Form EIA–411 submission has become less inclusive of the entire electric power industry. Mandatory collection authority for Form EIA–411 is necessary for EIA to collect the comprehensive information needed for public and private analysts to accurately monitor the current status and trends of the electric power industry, as well as to evaluate the future of the industry. This change in the reporting obligation for the EIA–411 is consistent with NERC's data program requirements because membership in NERC is now mandatory and data filing requirements by its members are also mandatory.

Form EIA–826, ''Monthly Electric Sales and Revenue With State Distributions Report''

It is proposed to reduce the due date for the form from 40 to 30 calendar days after the end of the reporting month to aid in validating the data against other survey data and to release the data to the public sooner.

Schedule 1. Part C. Sales to Ultimate Customers, Delivery Only Service

Additional requirement to provide the names of the energy service providers for whom distributors deliver electricity.

Form EIA–923, ''Power Plant Operations Report''

In addition to the information previously reported to EIA on the forms being superseded by the EIA–923, EIA proposes to collect the following additional items:

Schedule 2. Plant-Level

• Commodity cost (only for coal and natural gas) for the quantity of fuel receipts.
• Mercury content for the quality of fuel received (only for coal).
• Primary and secondary mode of transportation (only for coal and natural gas).
• Mine Safety and Health Administration (MSHA) identification number (for coal mine type and location).
• Also, all fossil fueled plants, including those which report to the Federal Energy Regulatory Commission (FERC) on the FERC Form 423 and with a capacity of 1 megawatt and greater, would now file this information.

Schedule 3. Part A—Boiler-Level

Consumption by energy source and heat content for plants with steam turbines of 10 megawatts or greater capacity that burn fossil or organic fuels (excluding steam turbines whose source of steam is from nuclear, geothermal or solar resources). Annual submitters would be required to provide 12 individual months worth of information. (**Note:** All other respondents would continue to provide prime mover level data on Schedule 4B.)

Schedule 5. Part A—Prime Mover-Level

Net and gross generation for all steam-electric plants; gross generation for combined heat and power plants; and consumption by fuel type and heat content for plants with steam turbines of 10 megawatts or greater capacity that burn fossil or organic fuel (excluding steam turbines whose source of steam is from nuclear, geothermal or solar resources). (**Note:** All other respondents would continue to provide prime mover level data on Schedule 5B.)

Schedule 7. Plant-Level for Annual Data Sources and Disposition proposes to collect revenues associated with the resale of electricity.

Schedule 8. Annual Environmental Information

• Part A. Byproduct Disposition.
• Part B. Financial Information.
• Part C. Nitrogen Oxide Emission Controls.
• Part D. Cooling System Information.
• Part E. Flue Gas Particulate Collection Information.
• Part F. Flue Gas Desulfurization Unit Information.

Form EIA–860, ''Annual Electric Generator Report''

The EIA proposes to collect the following additional items:

Schedule 2. Power Plant Data

• Boiler status.
• Boiler type.
• Name of the owner of the transmission system to which the power plant is connected (for all plants).

Schedule 3. Generator Information

• Whether the generator is an electric utility or nonutility.
• Associated boiler IDs (steam-electric generators only).
• For combined cycle steam generators, whether there is an associated duct-burner.
• Leading and lagging reactive power output at net summer and at net winter capacity.
• Primary start-up and flame stabilization energy sources.
• Factors that limit the ability to switch from natural gas to oil for an extended period.
• Whether the generator is part of a site that was previously reported as indefinitely postponed or cancelled.
• Type of technology for proposed coal-fired generator.

Schedule 6: Boiler Information

• Part A. Plant configuration.
• Part B. Air emission standards.
• Part C. Design parameters.
• Part D. Nitrogen oxide emission controls.
• Part E. Mercury emission controls.
• Part F. Cooling system information—design parameters.
• Part G. Flue gas particulate collector information.
• Part H. Flue gas desulfurization unit—design parameters.
• Part I. Stack and flue information—design parameters.

The EIA proposes to eliminate collecting the following items:

Schedule 3. Generator Information

• The name of the electric utility in whose service area the plant is located (applicable only to independent power producers and combined heat and power producers).
• Identification of distributed generators.
• The requirements to explicitly report the following for existing generators:
• Proposed for re-rating (EXCEPT nuclear generators).
• Proposed for deactivated shutdown status.
• Proposed for change in ownership.
• Proposed for fuel change.
• Proposed for reactivation from retirement.

Form EIA–860M, ''Monthly Update to the Annual Electric Generator Report''

Schedule B, Updates to Proposed Changes to Existing Generators

As a result of the proposal to modify Form EIA–860 to remove the requirements for reporting the following proposed changes associated with existing generators, the following reporting requirement is also proposed to be eliminated from the EIA–860M:

- The requirements to explicitly report the following for existing generators:
- Proposed for re-rating (EXCEPT nuclear generators).
- Proposed for deactivated shutdown status.
- Proposed for change in ownership.
- Proposed for fuel change.
- Proposed for reactivation from retirement.

Form EIA–861, ''Annual Electric Power Industry Report''

The EIA proposes to collect the following additional items:

Schedule 2C. Customer Service Programs

- Customer counts and green pricing revenue and volumes.

New Schedule 2D. Net Metering

- Net metering volumes.
- In addition to the number of customers served on net metering tariffs by end use class, the EIA will also capture electricity sales foregone by customers' use of net metering.

Schedule 6C. Demand Side Management

- Number of customers participating in incentive-based demand response programs.
- Number of customers participating in time-based rate programs.

Schedule 6D. Advance Metering

- The number of billing or revenue meters.
- The number of advanced customer meters and associated volumes.

Schedule 7A. Distributed and Dispersed Generation, Number and Capacity

- The number of generators and their capacity by State, and percent of capacity owned by respondent.

EIA proposes to eliminate: Schedule 7C. Types of Energy Sources Used. The EIA is proposing the following changes to the provisions regarding protected information reported on the electric power surveys.

The EIA proposes not to apply disclosure limitation methods to the disseminated electric power survey data. EIA's disclosure limitation methods are designed to minimize the possibility that individually-identifiable information reported by a survey respondent may be inferred from published statistics. Disclosure limitation methods consider how many respondents submitted information that was used to generate a statistic as well as whether any single respondent is responsible for a very large percentage of the value of a statistic. If disclosure limitation methods were applied, some electric power statistics would be suppressed from publication and unavailable to public and private analysts. By not applying disclosure limitation methods to electric power statistics, a knowledgeable person may be able to estimate the values of selected data elements reported by a specific respondent. The high utility of releasing aggregated statistics to the industry and the public supports the need not to apply disclosure limitation methods to the published statistics. However, EIA will not explicitly release individually identifiable data.

The merging of several electric power survey forms along with the policy not to apply disclosure limitation methods to statistics based on these survey data will help ensure EIA's continuing ability to disseminate detailed information on the electric power sector, and allow others to evaluate the effectiveness of laws and regulations such as the Energy Policy Act of 2005 and those developed by the Environmental Protection Agency for implementing requirements from the Clean Air Act Amendments of 1990.

The EIA will continue to protect the following data elements listed below and will not disclose to the public individually-identifiable data to the extent that it satisfies the criteria for exemption under the Freedom of Information Act (FOIA), 5 U.S.C. 552, the DOE regulations implementing the FOIA, 10 CFR 1004.11, and the Trade Secrets Act, 18 U.S.C. 1905:

- Fuel cost (current Form EIA–423, proposed Form EIA–923).
- Fuel stocks (current Form EIA–906 and Form EIA–920, and the proposed Form EIA–923).
- Commodity cost (proposed Form EIA–923).
- Monthly retail sales, revenue, and number of customers (for energy service providers only) (Form EIA–826).
- Maximum tested heat rate under full load conditions (Form EIA–860).
- Maps and power flow cases (Form EIA–411).

However, the EIA proposes to release the following data elements that either were protected before or will be collected for the first time:

- Monthly electric sales, revenue and number of customers for energy service providers on the Form EIA–826 nine (9) months after the end of the reporting year. These same annual data reported on the Form EIA–861 are currently not protected.
- Monthly fuel cost, commodity cost and fuel stocks on the proposed Form EIA–923 nine (9) months after the end of the reporting year.
- Latitude and longitude reported on the Form EIA–860. This information is available from many other external sources and is not considered vital to national security interests. These data will only be released upon request and will not be electronically available for the public to access through the Internet.

The majority of the electric power survey data are currently non-confidential. Protecting the monthly data on commodity and fuel costs and fuel stocks until nine (9) months after the end of the reporting year coincides with the release by the EIA of the reports *State Energy Profiles and Electric Power Annual*. These reports present data from 1990 to the present on electricity generation; electric generating capacity; capacity resource margins; fuel consumption; emissions; electricity trade; retail electric customers, sales, revenue and price; electric utility revenue and expense statistics; and demand-side management. The policy to release these data nine (9) months after the end of the reporting year supports the EIA's mandate for carrying out a central, comprehensive, and unified energy data and information program responsive to users' needs. It also supports EIA's mandate to release credible, reliable, and timely energy information that will improve and broaden the understanding of market activity in the electric power generation and distribution system, and help assess the reliability of the electric power grid in the United States. In addition, this release would not harm the individual companies, as sufficient time will have passed after the reporting month so that the data will have aged enough to no longer be of competitive interest to any competitors. If EIA receives approval to publicly release the company-level monthly information mentioned above, nine months after the end of a reporting year, EIA may later also undertake the process to publicly release such information collected prior to 2008 under similar conditions.

III. Request for Comments

Prospective respondents and other interested parties should comment on the proposals discussed in Item II. The following guidelines are provided to assist in the preparation of comments. Please indicate to which form(s) your comments apply.

General Issues

A. Are the proposed collections of information necessary for the proper performance of the functions of the agency and does the information have practical utility? Practical utility is defined as the actual usefulness of information to or for an agency, taking into account its accuracy, adequacy, reliability, timeliness, and the agency's ability to process the information it collects.

B. What enhancements can be made to the quality, utility, and clarity of the information to be collected?

C. Does EIA's proposed data protection treatment for electric power survey information maximize the utility of the data for users while adequately protecting sensitive information?

As a Potential Respondent to the Request for Information

A. What actions could be taken to help ensure and maximize the quality, objectivity, utility, and integrity of the information to be collected?

B. Are the instructions and definitions clear and sufficient? If not, which instructions need clarification?

C. Can the information be submitted by the due dates?

D. Public reporting burden for the average collection time are estimated below.

The estimated burden includes the total time necessary to provide the requested information. In your opinion, how accurate are these estimates? Form EIA–411, ''Bulk Power Supply Program Report,''—15.9 hours per response; Form EIA–923, ''Power Plant Operations Report,''—3.1 hours per response; Form EIA–826, ''Monthly Electric Sales and Revenue with State Distributions Report,'' 1.2 hours per response; Form EIA–860, ''Annual Electric Generator Report,''—8.5 hours per response; Form EIA–861, ''Annual Electric Power Industry Report,''—8.5 hours per response; Form EIA–860M, ''Monthly Update to the Annual Electric Generator Report,''—0.3 hour per response.

E. The agency estimates that the only cost to a respondent is for the time it will take to complete the collection. Will a respondent incur any start-up costs for reporting, or any recurring annual costs for operation, maintenance, and purchase of services associated with the information collection?

F. What additional actions could be taken to minimize the burden of this collection of information? Such actions may involve the use of automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

G. Does any other Federal, State, or local agency collect similar information? If so, specify the agency, the data element(s), and the methods of collection.

As a Potential User of the Information To Be Collected

A. What actions could be taken to help ensure and maximize the quality, objectivity, utility, and integrity of the information disseminated?

B. Is the information useful at the levels of detail to be collected?

C. For what purpose(s) would the information be used? Be specific.

D. Are there alternate sources for the information and are they useful? If so, what are their weaknesses and/or strengths?

Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval of the form. They also will become a matter of public record.

Statutory Authority: Sections 3506(c)(2) and 3507(a) of the Paperwork Reduction Act of 1995 (Pub. L. 104–13, 44 U.S.C. 3501, *et seq.*).

Issued in Washington, DC, March 27, 2007.

Jay H. Casselberry,

Agency Clearance Officer, Energy Information Administration.

[FR Doc. E7–6268 Filed 4–3–07; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP07–23–002]

Columbia Gas Transmission Corporation; Notice of Cancellation of Rate Schedule X–27

March 29, 2007.

Take notice that on March 14, 2007, Columbia Gas Transmission Corporation (Columbia) tendered for filing as part of its FERC Gas Tariff, the following changes to its tariff, effective February 27, 2007:

Second Revised Volume No. 1
Fourth Revised Sheet No. 4
Original Volume No. 2
Fifteenth Revised Sheet No. 2
First Revised Sheet No. 283

Any person desiring to protest this filing must file in accordance with Rule 211 of the Commission's Rules of Practice and Procedure (18 CFR 385.211). Protests to this filing 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. Such protests must be filed on or before the date as indicated below. Anyone filing a protest must serve a copy of that document on all the parties to the proceeding.

The Commission encourages electronic submission of protests in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov*. Persons unable to file electronically should submit an original and 14 copies of the protest to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible online at *http://www.ferc.gov*, using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov*, or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Comment Date: 5 p.m. Eastern Time on April 13, 2007.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–6204 Filed 4–3–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP07–362–000]

Columbia Gas Transmission Corporation; Notice of Proposed Changes in FERC Gas Tariff

March 29, 2007.

Take notice that on March 26, 2007 Columbia Gas Transmission Corporation (Columbia) tendered for filing as part of its FERC Gas Tariff, Second Revised Volume No. 1, the tariff sheets listed on Appendix A attached to the filing, bearing a proposed effective date of April 26, 2007.

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 and 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 in accordance with the provisions of Section 154.210 of the Commission's regulations (18 CFR 154.210). Anyone filing an intervention or protest must serve a copy of that document on the Applicant. Anyone filing an intervention or protest on or before the intervention or protest date need not serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov,* using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–6210 Filed 4–3–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP07–363–000]

Columbia Gas Transmission Corporation; Notice of Tariff Filing and Non-Conforming Service Agreements

March 29, 2007.

Take notice that on March 26, 2007 Columbia Gas Transmission Corporation (Columbia) tendered for filing as part of its FERC Gas Tariff, Second Revised Volume No. 1, Eighteenth Revised Sheet No. 500B, with a proposed effective date of May 1, 2007.

Columbia also tendered for filing the following Service Agreements for consideration and approval:

FTS Service Agreement No. 91804, between Columbia Gas Transmission Corporation and Chesapeake Appalachia, LLC, dated February 7, 2007.

FTS Service Agreement No. 91805, between Columbia Gas Transmission Corporation and Chesapeake Appalachia, LLC, dated February 7, 2007.

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 and 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 in accordance with the provisions of Section 154.210 of the Commission's regulations (18 CFR 154.210). Anyone filing an intervention or protest must serve a copy of that document on the Applicant. Anyone filing an intervention or protest on or before the intervention or protest date need not serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov,* using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–6211 Filed 4–3–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP07–172–001]

Columbia Gulf Transmission Company; Notice of Compliance Filing

March 29, 2007.

Take notice that on March 23, 2007, Columbia Gulf Transmission Company (Columbia Gulf) tendered for filing as part of its FERC Gas Tariff, Second Revised Volume No. 1, Second Revised Sheet No. 148, bearing a proposed effective date of March 17, 2007.

Any person desiring to protest this filing must file in accordance with Rule 211 of the Commission's Rules of Practice and Procedure (18 CFR 385.211). Protests to this filing 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. Such protests must be filed in accordance with the provisions of § 154.210 of the Commission's regulations (18 CFR 154.210). Anyone filing a protest must serve a copy of that document on all the parties to the proceeding.

The Commission encourages electronic submission of protests in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and 14 copies of the protest to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible online at *http://www.ferc.gov,* using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–6209 Filed 4–3–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP07–116–000]

El Paso Natural Gas Company; Notice of Request Under Blanket Authorization

March 29, 2007.

Take notice that on March 27, 2007, El Paso Natural Gas Company (EPNG), Post Office Box 1087, Colorado Springs, Colorado 80944, filed in Docket No. CP07–116–000, a prior notice request pursuant to §§ 157.205 and 157.208 of the Federal Energy Regulatory Commission's regulations under the Natural Gas Act for authorization to increase the maximum allowable operating pressure (MAOP) of the Slaughter Plant Line (Line No. 3000), originating in Cochran County, Texas and terminating in Hockley County, Texas, all as more fully set forth in the application, which is on file with the Commission and open to public inspection. The filing may also be viewed on the Web 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, contact FERC at *FERCOnlineSupport@ferc.gov* or call toll-free, (886) 208–3676 or TYY, (202) 502–8659.

Specifically, EPNG proposes to increase the MAOP on Line No. 3000, consisting of approximately 2.74 miles of 12¾ inch diameter pipeline, from a current MAOP of 744 psig to 780 psig and to thereafter operate Line No. 3000 at pressures up to and including the higher MAOP. EPNG states that the increase of the MAOP will allow EPNG certain operational flexibility and will have a de minimus effect on the current capacity of Line No. 3000. EPNG asserts that the cost of increasing the MAOP will be zero because existing test data for Line No. 3000 derived from a past pressure test and other historical information met the requirements to increase the MAOP to 780 psig.

Any questions regarding the application should be directed to Richard Derryberry, Director, Regulatory Affairs Department, El Paso Natural Gas Company, Post Office Box 1087, Colorado Springs, Colorado 80944, or call at (719) 520–3782.

Any person or the Commission's Staff may, within 60 days after the issuance of the instant notice by the Commission, file pursuant to Rule 214 of the Commission's Procedural Rules (18 CFR 385.214) a motion to intervene or notice of intervention and, pursuant to § 157.205 of the Commission's Regulations under the Natural Gas Act (NGA) (18 CFR 157.205) a protest to the request. If no protest is filed within the time allowed therefore, 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 shall be treated as an application for authorization pursuant to section 7 of the NGA.

The Commission strongly encourages electronic filings of comments, protests, and interventions via the Internet in lieu of paper. See 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site (*http://www.ferc.gov*) under the ''e-Filing'' link.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–6203 Filed 4–3–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. AC07–81–000]

Trans-Union Interstate Pipeline, L.P.; Notice of Filing

March 29, 2007.

Take notice that on March 23, 2007, Trans-Union Interstate Pipeline, L.P., submitted a request for a waiver of its requirement to submit a 2006 FERC Form No. 2–A. The FERC Form No. 2–A is required under section 260.2 of the Commission's regulations.

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 or 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 encourages electronic submission of protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov*. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible online at *http://www.ferc.gov*, using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov*, or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Comment Date: April 19, 2007.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–6202 Filed 4–3–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 11351–014]

Columbia Power & Water Systems; Notice of Availability of Environmental Assessment

March 29, 2007.

In accordance with the National Environmental Policy Act of 1969 and the Federal Energy Regulatory Commission (Commission or FERC) regulations contained in the Code of Federal Regulations (CFR) (18 CFR Part 380) [FERC Order No. 486, 52 FR 47897], the Office of Energy Project's staff (staff) reviewed a proposal to surrender the license for the Old Columbia Dam Project, and prepared an environmental assessment (EA) for this proposed surrender. In this EA, staff evaluates potential effects of the proposed surrender and finds that there would be no effects to aquatic or terrestrial resources, threatened or endangered species, recreation resources, or land use. The Commission also determined that the proposed surrender may adversely affect properties listed in the National Register due to the loss of Federal jurisdiction, and executed a Memorandum of Agreement (MOA) with the Tennessee State Historic Preservation Officer, pursuant to 36 CFR part 800.3 and 36 CFR part 800.6 of the Advisory Council on Historic Preservation regulations implementing Section 106 of the National Historic Preservation Act (16

U.S.C. 470f), in order to mitigate the adverse effects of the proposed surrender. The EA concludes that the proposed action will not constitute a major federal action significantly affecting the human environment.

A copy of the EA is attached to Commission order titled ''Order Approving Surrender of License'', issued March 28, 2007 and is available for review at the Commission in the Public Reference Room, located at 888 First Street, NE., Room 2A, Washington, DC 20426, or may be viewed on the Commission's Web site 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, call toll-free 1–866–209–3676 or e-mail *FERCOnlineSupport@ferc.gov.* For TTY, call (202) 502–8659.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–6206 Filed 4–3–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 2107–016—CA]

Pacific Gas and Electric Company; Notice of Availability of Final Environmental Assessment

March 29, 2007.

In accordance with the National Environmental Policy Act of 1969 and the Federal Energy Regulatory Commission's (Commission) regulations, 18 CFR part 380 (Order No. 486, 52 FR 47897), the Office of Energy Projects has reviewed the application for license for the Poe Hydroelectric Project, located on the North Fork Feather River in Butte County, California, and has prepared a final environmental assessment (EA) for the project. A draft EA was prepared and issued for public comment on August 2, 2006. The project occupies 144 acres of lands of the United States, which are administered by the Forest Supervisor of the Plumas National Forest.

The final EA contains the staff's analysis of the potential environmental impacts of the project and alternatives and concludes that licensing the project, with appropriate environmental protective measures, would not constitute a major federal action that would significantly affect the quality of the human environment.

A copy of the final EA is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site 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, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at 1–866–208–3676, or for TTY, (202) 502–8659.

You may also register online at *http://www.ferc.gov/docs-filing/esubscription.asp* to be notified via e-mail of new filings and issuances related to this or other pending projects. For assistance, contact FERC Online Support.

For further information, contact John Mudre at (202) 502–8902.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–6207 Filed 4–3–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Declaration of Intention and Soliciting Comments, Protests, and/or Motions To Intervene

March 29, 2007.

Take notice that the following application has been filed with the Commission and is available for public inspection:

a. *Application Type:* Declaration of Intention.

b. *Docket No.:* DI07–6–000.

c. *Date Filed:* March 13, 2007.

d. *Applicant:* Preston G. Curtis—Old Webb's Mill Hydro.

e. *Name of Project:* Old Webb's Mill Hydroelectric Project.

f. *Location:* The proposed Old Webb's Mill Hydroelectric Project will be located on the Tar River, which becomes the Pamlico River, tributary to the Atlantic Ocean, near Spring Hope in Nash County, North Carolina.

g. *Filed Pursuant to:* Section 23(b)(1) of the Federal Power Act, 16 U.S.C. 817(b).

h. *Applicant Contact:* Preston G. Curtis and Cathy Curtis, 10150 W. Highway 97, Middlesex, NC 27557; telephone: (252) 478–9161, fax: (252) 478–2950; e-mail: *curtiscompanies@costalnet.com.*

i. *FERC Contact:* Any questions on this notice should be addressed to Henry Ecton, (202) 502–8768, or E-mail address: *henry.ecton@ferc.gov.*

j. *Deadline for filing comments, protests, and/or motions:* April 30, 2007.

All documents (original and eight copies) should be filed with: Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. Comments, protests, and/or interventions may be filed electronically via the Internet in lieu of paper. Any questions, please contact the Secretary's Office. See, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site at *http://www.ferc.gov.* Please include the docket number (DI07–6–000) on any comments, protests, and/or motions filed.

k. *Description of Project:* The Old Webb's Mill Hydroelectric Project includes: (1) A 200-foot-long, 10-foot-high stone-and-concrete dam; (2) a powerhouse containing three generators rated at 400 kW; (3) one-foot-high flashboards; and (4) appurtenant facilities. The project will not occupy any tribal or federal lands.

When a Declaration of Intention is filed with the Federal Energy Regulatory Commission, the Federal Power Act requires the Commission to investigate and determine if the interests of interstate or foreign commerce would be affected by the project. The Commission also determines whether or not the project: (1) Would be located on a navigable waterway; (2) would occupy or affect public lands or reservations of the United States; (3) would utilize surplus water or water power from a government dam; or (4) if applicable, has involved or would involve any construction subsequent to 1935 that may have increased or would increase the project's head or generating capacity, or have otherwise significantly modified the project's pre-1935 design or operation.

l. *Locations of the Application:* Copies of this filing are on file with the Commission and are available for public inspection. This filing may be viewed on the web at *http://www.ferc.gov* using the ''eLibrary'' link, select ''Docket#'' and follow the instructions. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or TTY, contact (202) 502–8659.

m. Individuals desiring to be included on the Commission's mailing list should so indicate by writing to the Secretary of the Commission.

n. *Comments, Protests, or Motions to Intervene:* Anyone may submit comments, a protest, or a motion to intervene in accordance with the requirements of Rules of Practice and Procedure, 18 CFR 385.210, 385.211,

385.214. In determining the appropriate action to take, the Commission will consider all protests or other comments filed, but only those who file a motion to intervene in accordance with the Commission's Rules may become a party to the proceeding. Any comments, protests, or motions to intervene must be received on or before the specified comment date for the particular application.

o. *Filing and Service of Responsive Documents:* Any filings must bear in all capital letters the title ''COMMENTS'', ''PROTESTS'', AND/OR ''MOTIONS TO INTERVENE'', as applicable, and the Docket Number of the particular application to which the filing refers. A copy of any motion to intervene must also be served upon each representative of the Applicant specified in the particular application.

p. *Agency Comments:* Federal, state, and local agencies are invited to file comments on the described application. A copy of the application may be obtained by agencies directly from the Applicant. If an agency does not file comments within the time specified for filing comments, it will be presumed to have no comments. One copy of an agency's comments must also be sent to the Applicant's representatives.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–6205 Filed 4–3–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 2621–004]

Milliken and Company, Inc.; Notice of Intent To File License Application, Filing of Pre-Application Document, and Approving Use of the Traditional Licensing Process

March 29, 2007.

a. *Project No.:* 2621–004.

b. *Date Filed:* January 30, 2007.

c. *Submitted by:* Milliken and Company, Inc.

d. *Name of Project:* Pacolet River Hydroelectric Project.

e. *Location:* The project is located on the Pacolet River, in Spartanburg County, South Carolina.

f. *Filed Pursuant to:* 18 CFR 5.5 and 5.6 of the Commission's regulations.

g. *Potential Applicant Contact:* Mr. Bryan Stone, Business Manager, Lockhart Power Company, P.O. Box 10, 420 River Street, Lockhart, South Carolina 29364, (800) 368–1289.

h. *FERC Contact:* Lee Emery at (202) 502–8379; or e-mail at *lee.emery@ferc.gov.*

i. Pursuant to 18 CFR 5.3(a)(2), Milliken and Company, Inc. filed its Notice of Intent to File License Application using the Traditional Licensing Process on January 30, 2007. With this notice, the Director of the Office of Energy Projects approves Milliken and Company, Inc.'s request to use the Traditional Licensing Process.

j. *With this notice, we are initiating informal consultation with:* (a) The U.S. Fish and Wildlife Service and/or NOAA Fisheries under section 7 of the Endangered Species Act and the joint agency consultation at 50 CFR, part 402; (b) NOAA Fisheries under section 305(b) of the Magnuson-Stevens Fishery Conservation and Management Act and implementing regulations at 50 CFR 600.920; and (c) the South Carolina Historic Preservation Officer, as required by Section 106, National Historic Preservation Act, and the implementing regulations of the Advisory Council on Historic Preservation at 36 CFR 800.2.

k. With this notice, we are designating Milliken and Company, Inc. as the Commission's non-federal representative for carrying out informal consultation, pursuant to Section 7 of the Endangered Species Act, Section 305 of the Magnuson-Stevens Fishery Conservation and Management Act, and Section 106 of the National Historic Preservation Act.

l. Milliken and Company, Inc. filed a Pre-Application Document (PAD) with the Commission, pursuant to 18 CFR 5.6 of the Commission's regulations.

m. The licensee states its unequivocal intent to submit an application for a new license for Project No. 2197. Pursuant to 18 CFR 16.8, 16.9, and 16.10 each application for a new license and any competing license applications must be filed with the Commission at least 24 months prior to the expiration of the existing license. All applications for license for this project must be filed by January 31, 2010.

n. A copy of the PAD is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site (*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, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll free at 1–866–208–3676, or for TTY, at (202) 502–8659. A copy is also available for inspection and reproduction at the address in paragraph g.

Register online at *http://ferc.gov/esubscribenow.htm* to be notified via e-mail of new filing and issuances related to this or other pending projects. For assistance, contact FERC OnLine Support.

Philis J. Posey,

Acting Secretary.

[FR Doc. E7–6208 Filed 4–3–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Southeastern Power Administration

Proposed Rate Adjustment, Public Forum, and Opportunities for Public Review and Comment for Georgia-Alabama-South Carolina System of Projects

AGENCY: Southeastern Power Administration, DOE.

ACTION: Notice of proposed rate.

SUMMARY: Southeastern Power Administration (Southeastern) proposes to revise existing schedules of rates and charges applicable to the sale of power from the Georgia-Alabama-South Carolina System of Projects effective for a 5-year period, October 1, 2007, through September 30, 2012. Additionally, opportunities will be available for interested persons to review the present rates, the proposed rates and supporting studies, to participate in a forum and to submit written comments. Southeastern will evaluate all comments received in this process.

DATES: Written comments are due on or before July 3, 2007. A public information and comment forum will be held in Atlanta, Georgia, at 10 a.m., on May 10, 2007. Persons desiring to speak at the forum should notify Southeastern at least three (3) days before the forum is scheduled, so that a list of forum participants can be prepared. Others may speak if time permits.

ADDRESSES: Written comments should be submitted to: Administrator, Southeastern Power Administration, Department of Energy, 1166 Athens Tech Road, Elberton, Georgia 30635–6711. The public information and comment forum for the Georgia-Alabama-South Carolina System of Projects will be at the Hilton Garden Inn Atlanta Airport/Millenium Center, 2301 Sullivan Road, College Park, Georgia 30337 (404) 766–0303.

FOR FURTHER INFORMATION CONTACT: Leon Jourolmon, Assistant Administrator, Finance & Marketing, Southeastern Power Administration,

Department of Energy, 1166 Athens Tech Road, Elberton, Georgia 30635, (706) 213–3800.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (FERC) by order issued November 3, 2004 (109 FERC § 61,133), confirmed and approved on a final basis Wholesale Power Rate Schedules SOCO–1–B, SOCO–2–B, SOCO–3–B, SOCO–4–B, ALA–1–K, MISS–1–K, Duke–1–B, Duke–2–B, Duke–3–B, Duke–4–B, Santee–1–B, Santee–2–B, Santee–3–B, Santee–4–B, Pump–1–A, Pump–2, Regulation-1 and Replacement-1 applicable to Georgia-Alabama-South Carolina System of Projects' power for a period ending September 30, 2007.

Discussion: Existing rate schedules are predicated upon a July 2003 repayment study and other supporting data contained in FERC Docket No. EF03–3011–000. The current repayment study prepared in March 2007 shows that existing rates are not adequate to recover all costs required by present repayment criteria. Southeastern is proposing to establish rates that will recoup these unrecovered costs.

A revised study with a revenue increase of $13,045,000 in fiscal year 2008 and all future years over the current repayment study shows that all costs are repaid within their service life. Therefore, Southeastern is proposing to revise the existing rates to generate this additional revenue. The increase is due to increased operating expenses, including Corps Operation & Maintenance Expense and SEPA Marketing Expense.

Southeastern is proposing the following rate schedules to be effective for the period from October 1, 2007 through September 30, 2012.

Rate Schedule SOCO–1–C

Available to public bodies and cooperatives in Georgia, Alabama, Mississippi, and Florida to whom power may be wheeled and scheduled pursuant to contracts between the Government and Southern Company Services, Incorporated.

Rate Schedule SOCO–2–C

Available to public bodies and cooperatives in Georgia, Alabama, Mississippi, and Florida to whom power may be wheeled pursuant to contracts between the Government and Southern Company Services, Incorporated. The customer is responsible for providing a scheduling arrangement with the Government.

Rate Schedule SOCO–3–C

Available to public bodies and cooperatives in Georgia, Alabama, Mississippi, and Florida to whom power may be scheduled pursuant to contracts between the Government and Southern Company Services, Incorporated. The customer is responsible for providing a transmission arrangement.

Rate Schedule SOCO–4–C

Available to public bodies and cooperatives in Georgia, Alabama, Mississippi, and Florida. The customer is responsible for providing a scheduling arrangement with the Government and for providing a transmission arrangement.

Rate Schedule ALA–1–L

Available to the Alabama Electric Cooperative, Incorporated.

Rate Schedule MISS–1–L

Available to the South Mississippi Electric Power Association to whom power may be wheeled pursuant to contract between the Government and Alabama Electric Cooperative, Inc.

Rate Schedule Duke–1–C

Available to public bodies and cooperatives in North Carolina and South Carolina to whom power may be wheeled and scheduled pursuant to contracts between the Government and Duke Power Company.

Rate Schedule Duke–2–C

Available to public bodies and cooperatives in North Carolina and South Carolina to whom power may be wheeled pursuant to contracts between the Government and Duke Power Company. The customer is responsible for providing a scheduling arrangement with the Government.

Rate Schedule Duke–3–C

Available to public bodies and cooperatives in North Carolina and South Carolina to whom power may be scheduled pursuant to contracts between the Government and Duke Power Company. The customer is responsible for providing a transmission arrangement.

Rate Schedule Duke–4–C

Available to public bodies and cooperatives in North Carolina and South Carolina served through the transmission facilities of Duke Power Company. The customer is responsible for providing a scheduling arrangement with the Government and for providing a transmission arrangement.

Rate Schedule Santee–1–C

Available to public bodies and cooperatives in South Carolina to whom power may be wheeled and scheduled pursuant to contracts between the Government and South Carolina Public Service Authority.

Rate Schedule Santee–2–C

Available to public bodies and cooperatives in South Carolina to whom power may be wheeled pursuant to contracts between the Government and South Carolina Public Service Authority. The customer is responsible for providing a scheduling arrangement with the Government.

Rate Schedule Santee–3–C

Available to public bodies and cooperatives in South Carolina to whom power may be scheduled pursuant to contracts between the Government and South Carolina Public Service Authority. The customer is responsible for providing a transmission arrangement.

Rate Schedule Santee–4–C

Available to public bodies and cooperatives in South Carolina served through the transmission facilities of South Carolina Public Service Authority. The customer is responsible for providing a scheduling arrangement with the Government and for providing a transmission arrangement.

Rate Schedule SCE&G–1–C

Available to public bodies and cooperatives in South Carolina to whom power may be wheeled and scheduled pursuant to contracts between the Government and South Carolina Electric & Gas Company.

Rate Schedule SCE&G–2–C

Available to public bodies and cooperatives in South Carolina to whom power may be wheeled pursuant to contracts between the Government and South Carolina Electric & Gas Company. The customer is responsible for providing a scheduling arrangement with the Government.

Rate Schedule SCE&G–3–C

Available to public bodies and cooperatives in South Carolina to whom power may be scheduled pursuant to contracts between the Government and South Carolina Electric & Gas Company. The customer is responsible for providing a transmission arrangement.

Rate Schedule SCE&G–4–C

Available to public bodies and cooperatives in South Carolina served through the transmission facilities of South Carolina Electric & Gas Company. The customer is responsible for providing a scheduling arrangement with the Government and for providing a transmission arrangement.

Rate Schedule Pump–1–A

Available to all customers of the Georgia-Alabama-South Carolina System and applicable to energy from pumping operations at the Carters and Richard B. Russell projects.

Rate Schedule Pump–2

Available to public bodies and cooperatives who provide their own scheduling arrangement and elect to allow Southeastern to use a portion of their allocation for pumping.

Rate Schedule Regulation–1

Available to public bodies and cooperatives in Georgia, Alabama, Mississippi, Florida, South Carolina, or North Carolina to whom regulation service is provided pursuant to contracts between the Government and the customer.

Rate Schedule Replacement–1

Available to all customers in the Georgia-Alabama-South Carolina System and applicable to replacement energy.

The proposed rates for capacity, energy, and generation services are as follows:

Capacity: $3.75 per kw per month.

Energy: 9.43 mills per kwh.

Generation Services: $0.12 per kw per month.

Under this scenario, 75 per cent of generation revenues are recovered from capacity sales and 25 per cent are recovered from energy sales. These rates are expected to produce an average revenue increase of $13.0 million in FY 2008 and all future years.

The rates for transmission, scheduling, reactive supply, and regulation and frequency response apply to all four scenarios and are illustrated in Table 1.

SOUTHEASTERN POWER ADMINISTRATION PROPOSED RATES FOR TRANSMISSION SCHEDULING, REACTIVE, AND REGULATION CHARGES

Rate schedule	Transmission charge $/KW/month	Scheduling charge $/KW/month	Reactive charge $/KW/month	Regulation charge $/KW/month
SOCO–1–C	2.17	0.0806	0.11	0.0483
SOCO–2–C	2.17	N/A	0.11	N/A
SOCO–3–C	N/A	0.0806	N/A	0.0483
SOCO–4–C	N/A	N/A	N/A	N/A
ALA–1–L	N/A	N/A	N/A	N/A
MISS–1–L	2.25	N/A	N/A	N/A
Duke-1–C	0.87	N/A	N/A	N/A
Duke-2–C	0.87	N/A	N/A	N/A
Duke-3–C	N/A	N/A	N/A	N/A
Duke-4–C	N/A	N/A	N/A	N/A
Santee-1–C	1.06	N/A	N/A	N/A
Santee-2–C	1.06	N/A	N/A	N/A
Santee-3–C	N/A	N/A	N/A	N/A
Santee-4–C	N/A	N/A	N/A	N/A
SCE&G–1–C	0.85	N/A	N/A	N/A
SCE&G–2–C	0.85	N/A	N/A	N/A
SCE&G–3–C	N/A	N/A	N/A	N/A
SCE&G–4–C	N/A	N/A	N/A	N/A
Pump-1–A	N/A	N/A	N/A	N/A
Pump-2	N/A	N/A	N/A	N/A
Regulation-1	N/A	N/A	N/A	0.05
Replacement-1	N/A	N/A	N/A	N/A

The referenced repayment studies are available for examination at 1166 Athens Tech Road, Elberton, Georgia 30635–6711. Proposed Rate Schedules SOCO–1–C, SOCO–2–C, SOCO–3–C, SOCO–4–C, ALA–1–L, MISS–1–L, Duke-1–C, Duke-2–C, Duke-3–C, Duke-4–C, Santee-1–C, Santee-2–C, Santee-3–C, Santee-4–C, SCE&G–1–C, SCE&G–2–C, SCE&G–3–C, SCE&G–4–C, Pump-1–A, Pump-2, Regulation-1, and Replacement-1 are also available.

Dated: March 26, 2007.

Jon C. Worthington,

Administrator.

[FR Doc. E7–6257 Filed 4–3–07; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–8295–3]

Proposed Consent Decree, Clean Air Act Citizen Suit

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of proposed consent decree; request for public comment.

SUMMARY: In accordance with section 113(g) of the Clean Air Act, as amended (''CAA'' or ''Act''), 42 U.S.C. 7413(g), notice is hereby given of a proposed consent decree, to address a lawsuit filed by Rocky Mountain Clean Air Action and Jeremy Nichols (collectively ''Plaintiffs''): *Rocky Mountain Clean Air Action, et al.* v. *Johnson*, No. 06–01992 (D. D.C.). Plaintiffs filed deadline suits to compel the Administrator to respond to petitions seeking EPA's objection to CAA Title V operating permits filed in 2005 for the Public Service Company's Fort Saint Vrain Power Station (''Ft. St. Vrain Station'') in Colorado and in 2006 for the GCC Dacotah cement plant (''GCC Dacotah'') in South Dakota. Under the terms of the proposed consent decree, EPA has agreed to respond to the GCC Dacotah petition by June 15, 2007, and the Ft. St. Vrain Station petition is dismissed as moot because EPA took final action on February 5, 2007.

DATES: Written comments on the proposed consent decree must be received by May 4, 2007.

ADDRESSES: Submit your comments, identified by Docket ID number EPA–HQ–OGC–2007–0267, online at *www.regulations.gov* (EPA's preferred

method); by e-mail to *oei.docket@epa.gov*; mailed to EPA Docket Center, Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; or by hand delivery or courier to EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC, between 8:30 a.m. and 4:30 p.m. Monday through Friday, excluding legal holidays. Comments on a disk or CD–ROM should be formatted in Word or ASCII file, avoiding the use of special characters and any form of encryption, and may be mailed to the mailing address above.

FOR FURTHER INFORMATION CONTACT: David Orlin, Air and Radiation Law Office (2344A), Office of General Counsel, U.S. Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; telephone: (202) 564–1222; fax number (202) 564–5603; e-mail address: *orlin.david@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Additional Information About the Proposed Consent Decree

This proposed consent decree would resolve a lawsuit seeking a response to petitions to object to CAA Title V permits issued to the Ft. St. Vrain Station in Colorado and the GCC Dacotah plant in South Dakota. On February 5, 2007, EPA took final action on Plaintiffs' CAA Title V petition regarding Ft. St. Vrain Station. See 72 FR 13277 (Mar. 21, 2007). Under the consent decree, Plaintiffs' claim for relief for Ft. St. Vrain petition will be dismissed as moot except as to the issue of costs of litigation, including attorneys' fees. No later than June 15, 2007, EPA shall sign a decision, pursuant to 42 U.S.C. 7661d(b)(2), taking final action on Plaintiffs' petition on the GCC Dacotah permit. During a 60-day period after the decree is entered by the court, the parties shall seek to informally resolve any claim for litigation costs, including attorneys' fees, and if they cannot, Plaintiffs may seek such costs from the Court.

For a period of thirty (30) days following the date of publication of this notice, the Agency will receive written comments relating to the proposed consent decree from persons who were not named as parties or intervenors to the litigation in question. EPA or the Department of Justice may withdraw or withhold consent to the proposed consent decree if the comments disclose facts or considerations that indicate that such consent is inappropriate, improper, inadequate, or inconsistent with the requirements of the Act. Unless EPA or the Department of Justice determines, based on any comment which may be submitted, that consent to the consent decree should be withdrawn, the terms of the decree will be affirmed.

II. Additional Information About Commenting on the Proposed Consent Decree

A. How Can I Get A Copy of the Consent Decree?

The official public docket for this action (identified by Docket ID No. EPA–HQ–OGC–2007–0267) contains a copy of the proposed consent decree. The official public docket is available for public viewing at the Office of Environmental Information (OEI) Docket in the EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OEI Docket is (202) 566–1752.

An electronic version of the public docket is available through *www.regulations.gov.* You may use the *www.regulations.gov* to submit or view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. Once in the system, select ''search,'' then key in the appropriate docket identification number.

It is important to note that EPA's policy is that public comments, whether submitted electronically or in paper, will be made available for public viewing online at *www.regulations.gov* without change, unless the comment contains copyrighted material, CBI, or other information whose disclosure is restricted by statute. Information claimed as CBI and other information whose disclosure is restricted by statute is not included in the official public docket or in the electronic public docket. EPA's policy is that copyrighted material, including copyrighted material contained in a public comment, will not be placed in EPA's electronic public docket but will be available only in printed, paper form in the official public docket. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the EPA Docket Center.

B. How and To Whom Do I Submit Comments?

You may submit comments as provided in the **ADDRESSES** section. Please ensure that your comments are submitted within the specified comment period. Comments received after the close of the comment period will be marked ''late.'' EPA is not required to consider these late comments.

If you submit an electronic comment, EPA recommends that you include your name, mailing address, and an e-mail address or other contact information in the body of your comment and with any disk or CD ROM you submit. This ensures that you can be identified as the submitter of the comment and allows EPA to contact you in case EPA cannot read your comment due to technical difficulties or needs further information on the substance of your comment. Any identifying or contact information provided in the body of a comment will be included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment.

Use of the *www.regulations.gov* Web site to submit comments to EPA electronically is EPA's preferred method for receiving comments. The electronic public docket system is an ''anonymous access'' system, which means EPA will not know your identity, e-mail address, or other contact information unless you provide it in the body of your comment. In contrast to EPA's electronic public docket, EPA's electronic mail (e-mail) system is not an ''anonymous access'' system. If you send an e-mail comment directly to the Docket without going through *www.regulations.gov*, your e-mail address is automatically captured and included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket.

Dated: March 29, 2007.

Richard B. Ossias,

Associate General Counsel.

[FR Doc. E7–6235 Filed 4–3–07; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–ORD–2006–1010; FRL–8294–9]

Board of Scientific Counselors, Technology for Sustainability Subcommittee Meetings—April/May 2007

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of meetings.

SUMMARY: Pursuant to the Federal Advisory Committee Act, Public Law 92–463, the Environmental Protection Agency, Office of Research and Development (ORD), gives notice of two meetings (one face-to-face and one via conference call) of the Board of Scientific Counselors (BOSC) Technology for Sustainability Subcommittee.

DATES: The first meeting (a two-day face-to-face meeting) will be held on Wednesday, April 25, 2007, from 8 a.m. to 5 p.m., and Thursday, April 26, 2007 from 8 a.m. to 5 p.m. The second meeting (teleconference call) will be held on Wednesday, May 30, 2007 from 3 p.m. to 5 p.m. All times noted are eastern time. The meetings may adjourn early if all business is finished. Requests for the draft agenda or for making oral presentations at the meetings will be accepted up to 1 business day before each meeting.

ADDRESSES: Participation in the conference call will be by teleconference only—meeting rooms will not be used. Members of the public may obtain the call-in number and access code for the call from Clois Slocum, whose contact information is listed under the **FOR FURTHER INFORMATION CONTACT** section of this notice. The face-to-face meeting will be held at the at the Andrew W. Breidenbach Environmental Research Center (AWBERC) Facility, at 26 W. Martin Luther King Drive, Cincinnati, OH 45268. Submit your comments, identified by Docket ID No. EPA–HQ–ORD–2006–1010, by one of the following methods:

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *E-mail:* Send comments by electronic mail (e-mail) to: *ORD.Docket@epa.gov*, Attention Docket ID No. EPA–HQ–ORD–2006–1010.
- *Fax:* Fax comments to: (202) 566–0224, Attention Docket ID No. EPA–HQ–ORD–2006–1010.
- *Mail:* Send comments by mail to: Board of Scientific Counselors, Technology for Sustainability Subcommittee Meetings—Winter/Spring 2007 Docket, Mailcode: 28221T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Attention Docket ID No. EPA–HQ–ORD–2006–1010.
- *Hand Delivery or Courier.* Deliver comments to: EPA Docket Center (EPA/DC), Room B102, EPA West Building, 1301 Constitution Avenue, NW., Washington, DC, Attention Docket ID No. EPA–HQ–ORD–2006–1010. Note: this is not a mailing address. Such deliveries are only accepted during the docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–ORD–2006–1010. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or e-mail. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *www.regulations.gov*, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm*.

Docket: All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Board of Scientific Counselors, Technology for Sustainability Subcommittee Meetings—Winter/Spring 2007 Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the ORD Docket is (202) 566–1752.

FOR FURTHER INFORMATION CONTACT: The Designated Federal Officer via mail at: Clois Slocum, USEPA, 26 W. Martin Luther King Drive, Cincinnati, OH 45268; via phone/voice mail at: (513) 569–7281; via fax at: (513) 569–7549; or via e-mail at: *slocum.clois@epa.gov*.

SUPPLEMENTARY INFORMATION:

General Information

Any member of the public interested in receiving a draft BOSC agenda or making a presentation at either meeting may contact Clois Slocum, the Designated Federal Officer, via any of the contact methods listed in the **FOR FURTHER INFORMATION CONTACT** section above. In general, each individual making an oral presentation will be limited to a total of three minutes.

Proposed agenda items for the meetings include, but are not limited to: *face-to-face meeting:* presentations by key ORD staff in the sustainability research program, poster sessions, development of the draft report, and presentation of the subcommittee's draft responses to the charge questions; *teleconference:* discussion of the draft report from the review. The meetings are open to the public.

Information on Services for Individuals with Disabilities: For information on access or services for individuals with disabilities, please contact Clois Slocum (513) 569–7281 or *slocum.clois@epa.gov*. To request accommodation of a disability, please contact Clois Slocum, preferably at least 10 days prior to the meeting, to give EPA as much time as possible to process your request.

Dated: March 28, 2007.

Jeffery Morris,

Acting Director, Office of Science Policy.

[FR Doc. E7–6237 Filed 4–3–07; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–ORD–2007–0242; FRL–8295–1]

Board of Scientific Counselors, Drinking Water Mid-Cycle Subcommittee Meetings—Spring 2007

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of meetings.

SUMMARY: Pursuant to the Federal Advisory Committee Act, Public Law 92–463, the Environmental Protection Agency, Office of Research and Development (ORD), gives notice of two meetings of the Board of Scientific Counselors (BOSC) Drinking Water Mid-Cycle Subcommittee.

DATES: The first meeting (a teleconference call) will be held on Thursday, April 26, 2007, from 10 a.m. to 12:30 p.m. The second meeting (face-to-face meeting) will be held on Wednesday, May 23, 2007 from 9:30 a.m. to 3 p.m. All times noted are eastern time. The meetings may adjourn early if all business is finished. Requests for the draft agenda or for making oral presentations at the meetings will be accepted up to 1 business day before each meeting.

ADDRESSES: Participation in the conference call will be by teleconference only—meeting rooms will not be used. Members of the public may obtain the call-in number and access code for the calls from Edie Coates, whose contact information is listed under the **FOR FURTHER INFORMATION CONTACT** section of this notice. The face-to-face meeting will be held at the Newport Harbor Hotel and Marina, 49 America's Cup Avenue, Newport, Rhode Island 02840. Submit your comments, identified by Docket ID No. EPA–HQ–ORD–2007–0242, by one of the following methods:

- *http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *E-mail:* Send comments by electronic mail (e-mail) to: *ORD.Docket@epa.gov*, Attention Docket ID No. EPA–HQ–ORD–2007–0242.
- *Fax: Fax comments to:* (202) 566–0224, Attention Docket ID No. EPA–HQ–ORD–2007–0242.
- *Mail:* Send comments by mail to: Board of Scientific Counselors, Drinking Water Mid-Cycle Subcommittee Meeting—Spring 2007 Docket, *Mailcode:* 28221T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Attention Docket ID No. EPA–HQ–ORD–2007–0242.
- *Hand Delivery or Courier:* Deliver comments to: EPA Docket Center (EPA/DC), Room B102, EPA West Building, 1301 Constitution Avenue, NW., Washington, DC, Attention Docket ID No. EPA–HQ–ORD–2007–0242.

Note: this is not a mailing address. Such deliveries are only accepted during the docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–ORD–2007–0242. EPA's policy is that all comments received will be included in the public docket 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 Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov*, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm*.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Board of Scientific Counselors, Drinking Water Mid-Cycle Subcommittee Meeting—Spring 2007 Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the ORD Docket is (202) 566–1752.

FOR FURTHER INFORMATION CONTACT: The Designated Federal Officer via mail at: Edie Coates, Mail Drop B103–05, Neurotoxicology Division, National Health and Environmental Effects Research Laboratory, Office of Research and Development, Environmental Protection Agency, Research Triangle Park, North Carolina 27711; *via phone/voice mail at:* (919) 541–3508; *via fax at:* (919) 541–3335; or *via e-mail at: coates.edie@epa.gov*.

SUPPLEMENTARY INFORMATION:

General Information

Any member of the public interested in receiving a draft BOSC agenda or making a presentation at either meeting may contact Edie Coates, the Designated Federal Officer, via any of the contact methods listed in the **FOR FURTHER INFORMATION CONTACT** section above. In general, each individual making an oral presentation will be limited to a total of three minutes.

Proposed agenda items for the meetings include, but are not limited to: Teleconference: the objectives of the review; an overview of ORD's drinking water research program; a summary of major changes in the drinking water research program since 2005; and an update on the Drinking Water Multi-Year Plan; *face-to-face meeting:* the drinking water research program's progress in response to recommendations from its 2005 BOSC review and other activities. The meetings are open to the public.

Information on Services for Individuals with Disabilities: For information on access or services for individuals with disabilities, please contact Edie Coates at (919) 541–3508 or *coayes.edie@epa.gov*. To request accommodation of a disability, please contact Edie Coates, preferably at least 10 days prior to the meeting, to give EPA as much time as possible to process your request.

Dated: March 27, 2007.

Connie M. Bosma,

Acting Director, Office of Science Policy.

[FR Doc. E7–6239 Filed 4–3–07; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2007–0109; FRL–8119–6]

Calcium Thiosulfate; Notice of Receipt of Request to Voluntarily Cancel Certain Pesticide Registrations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In accordance with section 6(f)(1) of the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), as amended, EPA is issuing a notice of receipt of a request by a registrant to voluntarily cancel their registrations of certain products containing the pesticide calcium thiosulfate. The request would terminate the last calcium thiofulfate product registered for use in the U.S. EPA intends to grant this request at the close of the comment period for this announcement unless the Agency receives substantive comments within the comment period that would merit its further review of the request, or unless the registrant withdraws their request within this period. Upon acceptance of this request, any sale, distribution, or use of products listed in this notice will be permitted only if such sale, distribution, or use is consistent with the terms as described in the final order.

DATES: Comments must be received on or before May 4, 2007.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPP–2007–0109, by one of the following methods:

- *Federal eRulemaking Portal*: *http://www.regulations.gov*. Follow the on-line instructions for submitting comments.
- *Mail*: Office of Pesticide Programs (OPP) Regulatory Public Docket (7502P), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001.
- *Delivery*: OPP Regulatory Public Docket (7502P), Environmental Protection Agency, Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. Deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays). Special arrangements should be made for deliveries of boxed information. The Docket telephone number is (703) 305–5805.

Instructions: Direct your comments to docket ID number EPA–HQ–OPP–2007–0109. EPA's policy is that all comments received will be included in the docket without change and may be made available on-line at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through regulations.gov or e-mail. The Federal regulations.gov website is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through regulations.gov, your e-mail address will be automatically captured and included as part of the comment that is placed in the docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the docket index available in regulations.gov. To access the electronic docket, go to *http://www.regulations.gov*, select ''Advanced Search,'' then ''Docket Search.'' Insert the docket ID number where indicated and select the ''Submit'' button. Follow the instructions on the regulations.gov web site to view the docket index or access available documents. Although listed in the index, some information is not publicly available, e.g., 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 either in the electronic docket at *http://www.regulations.gov*, or, if only available in hard copy, at the OPP Regulatory Public Docket in Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. The hours of operation of this Docket Facility are from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The Docket telephone number is (703) 305–5805.

FOR FURTHER INFORMATION CONTACT: Katie Hall, Special Review and Reregistration Division (7508P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: (703) 308–0166; fax number: (703) 308–8090; e-mail address: *hall.katie@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

This action is directed to the public in general, and may be of interest to a wide range of stakeholders including environmental, human health, and agricultural advocates; the chemical industry; pesticide users; and members of the public interested in the sale, distribution, or use of pesticides. Since others also may be interested, the Agency has not attempted to describe all the specific entities that may be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed under **FOR FURTHER INFORMATION CONTACT**.

B. What Should I Consider as I Prepare My Comments for EPA?

1. *Submitting CBI*. Do not submit this information to EPA through regulations.gov or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for preparing your comments*. When submitting comments, remember to:

i. Identify the document by docket ID number and other identifying information (subject heading, **Federal Register** date and page number).

ii. Follow directions. The Agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

iii. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

iv. Describe any assumptions and provide any technical information and/or data that you used.

v. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

vi. Provide specific examples to illustrate your concerns and suggest alternatives.

vii. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

viii. Make sure to submit your comments by the comment period deadline identified.

II. Background on the Receipt of Requests to Cancel and/or Amend Registrations to Delete Uses

This notice announces receipt by EPA of a request from United Industries Corp. to cancel 8860–67 Liquid Lime-Sulphur 32 Degrees Baume product registration. In a letter dated January 24, 2007, United Industries Corp. requested EPA to cancel affected product registrations identified in this notice (Table 1). Specifically, United Industries Corp. requests voluntary cancellation of the product Liquid Lime-Sulphur 32 Degrees Baume due to lack of use. This product has never been manufactured or marketed by United Industries Corp. Action on the registrant's request will terminate the last calcium thiosulfate products registered in the United States.

III. What Action is the Agency Taking?

This notice announces receipt by EPA of a request from a registrant to cancel calcium thiosulfate product registrations. The affected products and the registrants making the requests are identified in Tables 1 and 2 of this unit.

Under section 6(f)(1)(A) of FIFRA, registrants may request, at any time, that their pesticide registrations be canceled or amended to terminate one or more pesticide uses. Section 6(f)(1)(B) of FIFRA requires that before acting on a request for voluntary cancellation, EPA must provide a 30–day public comment period on the request for voluntary cancellation or use termination. In addition, section 6(f)(1)(C) of FIFRA requires that EPA provide a 180–day comment period on a request for voluntary cancellation or termination of any minor agricultural use before granting the request, unless:

1. The registrants request a waiver of the comment period, or

2. The Administrator determines that continued use of the pesticide would pose an unreasonable adverse effect on the environment.

The calcium thiosulfate registrant has requested that EPA waive the 180–day comment period. EPA will provide a 30–day comment period on the proposed request.

Unless a request is withdrawn by the registrant within 30 days of publication of this notice, or if the Agency determines that there are substantive comments that warrant further review of this request, an order will be issued canceling the affected registration.

TABLE 1.—CALCIUM THIOSULFATE PRODUCT REGISTRATION WITH PENDING REQUESTS FOR CANCELLATION

Registration No.	Product name	Company
8660–67	Liquid Lime-Sulphur 32 Degrees Baume	United Industries Corp.

Table 2 of this unit includes the name and address of record for the registrant of the product listed in Table 1 of this unit.

TABLE 2.—REGISTRANT REQUESTING VOLUNTARY CANCELLATION

EPA Company No.	Company Name and Address
8660	United Industries Corp., P.O. Box 142642 St. Louis, MO 63114

IV. What is the Agency's Authority for Taking this Action?

Section 6(f)(1) of FIFRA provides that a registrant of a pesticide product may at any time request that any of its pesticide registrations be canceled or amended to terminate one or more uses. FIFRA further provides that, before acting on the request, EPA must publish a notice of receipt of any such request in the **Federal Register**. Thereafter, following the public comment period, the Administrator may approve such a request.

V. Procedures for Withdrawal of Request and Considerations for Reregistration of Calcium Thiosulfate

Registrants who choose to withdraw a request for cancellation must submit such withdrawal in writing to the person listed under **FOR FURTHER INFORMATION CONTACT**, *postmarked before 30 days after date of publication in the* **Federal Register**. This written withdrawal of the request for cancellation will apply only to the applicable FIFRA section 6(f)(1) request listed in this notice. If the products(s) have been subject to a previous cancellation action, the effective date of cancellation and all other provisions of any earlier cancellation action are controlling.

VI. Provisions for Disposition of Existing Stocks

Existing stocks are those stocks of registered pesticide products which are currently in the United States and which were packaged, labeled, and released for shipment prior to the effective date of the cancellation action. This Notice proposes the following existing stocks provision: The prohibition on sales, distribution, and use of existing stocks by the registrant will be effective on the date of the cancellation order.

Persons other than the registrant will be able to continue to sell and/or use existing stocks of cancelled products until such stocks are exhausted, provided that such use is consistent with the terms of the previously approved labeling on, or that accompanied, the cancelled product. The order will specifically prohibit any use of existing stocks that is not consistent with such previously approved labeling. If, as the Agency currently intends, the final cancellation order contains the existing stocks provision just described, the order will be sent only to the affected registrants of the cancelled products. If the Agency determines that the final cancellation order should contain existing stocks provisions different than the ones just described, the Agency will publish the cancellation order in the **Federal Register**.

List of Subjects

Environmental protection, Pesticides and pests.

Dated: March 22, 2007.

Debra Edwards,

Director, Special Review and Reregistration Division, Office of Pesticide Programs.

[FR Doc. E7–6059 Filed 4–3–07; 8:45 am]

BILLING CODE 6560–50–S

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2006–0936; FRL–8119–2]

Notice of Filing of Pesticide Petitions for Residues of Pesticide Chemicals in or on Various Commodities

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: This notice announces the initial filing of pesticide petitions proposing the establishment or modification of regulations for residues

of pesticide chemicals in or on various commodities.

DATES: Comments must be received on or before May 4, 2007.

ADDRESSES: Submit your comments, identified by docket identification (ID) number and the pesticide petition number (PP) of interest, by one of the following methods:

• *Federal eRulemaking Portal*: *http://www.regulations.gov.* Follow the on-line instructions for submitting comments.

• *Mail*: Office of Pesticide Programs (OPP) Regulatory Public Docket (7502P), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001.

• *Delivery*: OPP Regulatory Public Docket (7502P), Environmental Protection Agency, Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. Deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays). Special arrangements should be made for deliveries of boxed information. The Docket Facility telephone number is (703) 305–5805.

Instructions: Direct your comments to the assigned docket ID number and the pesticide petition number of interest. EPA's policy is that all comments received will be included in the docket without change and may be made available on-line at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through regulations.gov or e-mail. The regulations.gov website is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through regulations.gov, your e-mail address will be automatically captured and included as part of the comment that is placed in the docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the docket index available in regulations.gov. To access the electronic docket, go to *http://www.regulations.gov*, select ''Advanced Search,'' then ''Docket Search.'' Insert the docket ID number where indicated and select the ''Submit'' button. Follow the instructions on the regulations.gov website to view the docket index or access available documents. Although listed in the index, some information is not publicly available, e.g., 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. Publicly available docket materials are available electronically at *http://www.regulations.gov*, or, if only available in hard copy, at the OPP Regulatory Public Docket in Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. The hours of operation of this Docket Facility are from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The Docket Facility telephone number is (703) 305–5805.

FOR FURTHER INFORMATION CONTACT: The person listed at the end of the pesticide petition summary of interest.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. Potentially affected entities may include, but are not limited to:

• Crop production (NAICS code 111).

• Animal production (NAICS code 112).

• Food manufacturing (NAICS code 311).

• Pesticide manufacturing (NAICS code 32532).

This listing is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in this unit could also be affected. The North American Industrial Classification System (NAICS) codes have been provided to assist you and others in determining whether this action might apply to certain entities. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed at the end of the pesticide petition summary of interest.

B. What Should I Consider as I Prepare My Comments for EPA?

1. *Submitting CBI.* Do not submit this information to EPA through regulations.gov or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for preparing your comments.* When submitting comments, remember to:

i. Identify the document by docket ID number and other identifying information (subject heading, **Federal Register** date and page number).

ii. Follow directions. The Agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

iii. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

iv. Describe any assumptions and provide any technical information and/or data that you used.

v. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

vi. Provide specific examples to illustrate your concerns and suggest alternatives.

vii. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

viii. Make sure to submit your comments by the comment period deadline identified.

II. Docket ID Numbers

When submitting comments, please use the docket ID number and the pesticide petition number of interest, as shown in the table.

PP number	Docket ID number
PP 3E6562	EPA–HQ–OPP–2007–0107
PP 6E7138	EPA–HQ–OPP–2007–0107

PP number	Docket ID number
PP 6E7129	EPA–HQ–OPP–2007–0106
PP 6E7152	EPA–HQ–OPP–2007–0116
PP 6E7163	EPA–HQ–OPP–2007–0105
PP 6E7165	EPA–HQ–OPP–2007–0117
PP 5E6962	EPA–HQ–OPP–2005–0305
PP 5E7007	EPA–HQ–OPP–2005–0305
PP 6E7164	EPA–HQ–OPP–2007–0115
PP 6E7168	EPA–HQ–OPP–2007–0114
PP 5E6996	EPA–HQ–OPP–2005–0306

III. What Action is the Agency Taking?

EPA is printing notice of the filing of pesticide petitions received under section 408 of the Federal Food, Drug, and Cosmetic Act (FFDCA), 21 U.S.C. 346a, proposing the establishment or modification of regulations in 40 CFR part 180 for residues of pesticide chemicals in or on various food commodities. EPA has determined that the pesticide petitions described in this notice contain data or information regarding the elements set forth in FFDCA section 408(d)(2); however, EPA has not fully evaluated the sufficiency of the submitted data at this time or whether the data support granting of the pesticide petitions. Additional data may be needed before EPA rules on these pesticide petitions.

Pursuant to 40 CFR 180.7(f), a summary of each of the petitions included in this notice, prepared by the petitioner, is included in a docket EPA has created for each rulemaking. The docket for each of the petitions is available on-line at *http://www.regulations.gov*.

Amendment to Existing Tolerances

1. *PPs 3E6562* and *6E7138*. (Docket ID number EPA–HQ–OPP–2007–0107). Interregional Research Project Number 4 (IR–4), 500 College Road East, Suite 201 W, Princeton, NJ 08540, proposes to amend 40 CFR 180.443 by establishing tolerances for residues of the fungicide myclobutanil in or on the food commodities in *PP 3E6562*: Black sapote, canistel, mamey sapote, mango, papaya, sapodilla, and star apple at 3.0 parts per million (ppm); and in *PP 6E7138*: Fruiting vegetables, crop group 8, except tomato at 4.5 ppm; leafy vegetables, crop subgroup 4A, except spinach at 11.0 ppm; globe artichoke at 0.9 ppm; cilantro at 11.0 ppm; and okra at 4.5 ppm. The residue analytical method used was Rohm and Haas Company method 34S–88–10, ''RH–3866 total residue analytical method for apple, and grape'' for artichokes, lettuce, pepper, and tropical fruits; and Rohm and Haas method TR34S–88–21, ''Analytical method for the measure of RH–3866 in various crops, soil, meat, milk and eggs''. The lowest level of method validation (LLMV) in this study was 0.01 ppm for each analyte. Based on recoveries of samples fortified at the LLMV, the limit of detection (LOD) and the limit of quantitation (LOQ) were estimated as 0.0036 ppm and 0.011 ppm; respectively, for myclobutanil as 0.018 ppm and 0.054 ppm; respectively, for RH–9090. Contact: Barbara Madden, telephone number: (703) 305–6463; e-mail address: *madden.barbara@epa.gov*.

2. *PP 6E7129*. (Docket ID number EPA–HQ–OPP–2007–0106). Interregional Research Project Number 4 (IR–4), 500 College Road East, Suite 201 W, Princeton, NJ 08540, proposes to amend 40 CFR 180.361 by establishing tolerances for residues of the herbicide pendimethalin, [N-(1-ethylpropyl)-3,4-dimethyl-2,6-dinitrobenzenamine] and its metabolite 4-[(1-ethylpropyl)amino]-2-methyl-3,5-dinitrobenzyl alcohol in or on the food commodities Brassica, head and stem, subgroup 5A at 0.05 ppm; grape at 0.05 ppm; artichoke, globe at 0.05 ppm; and asparagus at 0.1 ppm. The analytical method in plants is aqueous organic solvent extraction, column clean-up, and quantitation by gas chromatography (GC). The method has a LOQ of 0.05 ppm for pendimethalin and the alcohol metabolite. Contact: Barbara Madden, telephone number: (703) 305–6463; e-mail address: *madden.barbara@epa.gov*.

3. *PP 6E7152*. (Docket ID number EPA–HQ–OPP–2007–0116). Interregional Research Project Number 4 (IR–4), 500 College Road East, Suite 201 W, Princeton, NJ 08540, proposes to amend 40 CFR 180.361 by establishing tolerances for residues of the herbicide dimethenamid, (R,S)-2-chloro-N-[(1-methyl-2-methoxy) ethyl]-N-(2,4-dimethyl-thien-3-yl)-acetamide in or on the food commodities squash, winter at 0.01 ppm; pumpkin at 0.01 ppm; radish, roots at 0.01 ppm; radish, tops at 0.01 ppm; turnip, roots at 0.01 ppm; turnip, tops at 0.01 ppm; rutabaga, roots at 0.01 ppm; rutabaga, tops at 0.01 ppm; and hops, dried cones 0.05 ppm. The proposed analytical method uses extraction and clean-up followed by quantification with capillary column GC using thermionic nitrogen specific detector. A gas spectrometry/mass spectrometry (GS/MS) method for identification is also available. This method is not selective towards the dimethenamid isomer and is therefore valid for residues from both racemic dimethenamid and the enriched isomer dimethenamid-P. Tolerances are proposed based on a non-isomer specific basis. Contact: Shaja Brothers, telephone number: (703) 308–3194; e-mail address: *brothers.shaja@epa.gov*.

4. *PP 6E7163*. (Docket ID number EPA–HQ–OPP–2007–0105). Interregional Research Project Number 4 (IR–4), 500 College Road East, Suite 201 W, Princeton, NJ 08540, proposes to amend 40 CFR 180.578 by establishing tolerances for residues of the insecticide acetamiprid, N1-[(6-chloro-3-pyridyl)methyl]-N2-cyano-N1-methylacetamidine in or on the food commodities strawberry, bearberry, bilberry, lowbush blueberry, cloudberry, cranberry, ligonberry, muntries, and partridgeberry at 0.60 ppm. Based upon the metabolism of acetamiprid in plants and the toxicology of the parent, and metabolites quantification of the parent acetamiprid is sufficient to determine toxic residues. As a result, a method has been developed which involves extraction of acetamiprid from crops with methanol and analysis by liquid chromatography/tandem mass spectrometry (LC/MS/MS) methods. The LOQ and the LOD for the method are calculated to be 0.002 ppm and 0.0008 ppm for strawberries, respectively. The LLMV for strawberries was 0.01 ppm for acetamiprid. Contact: Barbara Madden, telephone number: (703) 305–6463; e-mail address: *madden.barbara@epa.gov*.

5. *PP 6E7165*. (Docket ID number EPA–HQ–OPP–2007–0117). Interregional Research Project Number 4 (IR–4), 500 College Road East, Suite 201 W, Princeton, NJ 08540, proposes to amend 40 CFR 180.582 by establishing tolerances for residues of the fungicide pyraclostrobin, (carbamic acid, [2-[[[1-(4-chlorophenyl)-1H-pyrazol-3-yl]oxy]methyl] phenyl]methoxy-, methyl ester) and its metabolite (methyl-N-[[[1-(4-chlorophenyl) pyrazol-3-yl]oxy]o-tolyl] carbamate) (BF 500-3) expressed as parent compound in or on the food commodities herbs, fresh at 30.0 ppm; avocado at 0.7 ppm; mango at 0.7 ppm; papaya at 0.7 ppm; sapote, black at 0.7 ppm; sapote, mamey at 0.7 ppm; canistel at 0.7 ppm; sapodilla at 0.7 ppm; and star apple at 0.7 ppm. In plants the method of analysis is aqueous organic solvent extraction, column clean-up and quantitation by LC/MS/MS. In animals the method of analysis

involves base hydrolysis, organic extraction, column clean up and quantitation by LC/MS/MS or derivatization (methylation) followed by quantitation by GC/MS. Contact: Shaja R. Brothers, telephone number: (703) 308–3194; e-mail address: *brothers.shaja@epa.gov*.

6. *PP 5E6962*. (Docket ID number EPA–HQ–OPP–2005–0305). Interregional Research Project Number 4 (IR–4), 681 U.S. Highway #1 South, North Brunswick, NJ 08902–3390; and Bayer CropScience, 2 T.W. Alexander Drive, Research Triangle Park, NC 27709, proposes to amend the tolerances in 40 CFR 180.570 for residues of the isoxadifen-ethyl (ethyl 5,5-diphenyl-2-isoxazoline -3-carboxylate) and its metabolite 4,5-dihydro-5,5,diphenyl-3-isoxazolecarboxylic acid when used as an inert ingredient (safener) in or on the food commodities corn, field, forage at 0.20 ppm (increased from existing tolerance of 0.10 ppm), and corn, field, stover at 0.40 ppm (increased from existing tolerance of 0.20 ppm); (request removal of the specified limitation in seasonal application rate from the existing tolerances); and isoxadifen-ethyl and its metabolites 4,5-dihydro-5,5,diphenyl -3-isoxazolecarboxylic acid and β-hydroxy-β-benzenepropanenitrile when used as an inert ingredient (safener) in or on the following raw agricultural commodities: Rice, grain at 0.10 ppm; rice, hulls at 0.50 ppm; and rice, straw at 0.25 ppm (request removal of the specified limitation in seasonal application rate from the existing tolerances). The analytical targets selected were the parent compound, isoxadifen-ethyl and the major metabolite isoxadifen acid (AE F129431). In rice, AE C637375 and AE F162241 are also determined. After extraction and cleanup, the analytes are determined by either GC/MS or HPLC/MS. The LOQ are 0.02 ppm in corn grain, 0.05 ppm in corn forage and stover, and 0.02 ppm in rice. Contact: Shaja R. Brothers, telephone number: (703) 308–3194; e-mail address: *brothers.shaja@epa.gov*.

New Tolerances

1. *PP 5E7007*. (Docket ID number EPA–HQ–OPP–2005–0305). Interregional Research Project Number 4 (IR–4), 681 U.S. Highway #1 South, North Brunswick, NJ 08902–3390; and Bayer CropScience, 2 T.W. Alexander Drive, Research Triangle Park, NC 27709, proposing pursuant to section 408(d) of the Federal Food, Drug, and Cosmetic Act (FFDCA), 21 U.S.C. 346a(d), to amend 40 CFR part 180 by establishing a tolerance for residues of isoxadifen-ethyl, (ethyl 5,5-diphenyl-2-isoxazoline-3-carboxylate) and its metabolite 4,5-dihydro-5,5,diphenyl-3-isoxazolecarboxylic acid when used as an inert ingredient (safener) in or on the food commodities corn, sweet, kernel plus cob with husks removed at 0.05 ppm; corn, sweet, forage at 0.40 ppm; corn, sweet, stover at 0.40 ppm; corn, pop, grain at 0.02 ppm; and corn, pop, stover at 0.40 ppm. The analytical targets selected were the parent compound, isoxadifen-ethyl and the major metabolite isoxadifen acid (AE F129431). In rice, AE C637375 and AE F162241 are also determined. After extraction and clean-up, the analytes are determined by either GC/MS or HPLC/MS. The LOQ are 0.02 ppm in corn grain, 0.05 ppm in corn forage and stover, and 0.02 ppm in rice. Contact: Shaja R. Brothers, telephone number: (703) 308–3194; e-mail address: *brothers.shaja@epa.gov*.

2. *PP 6E7164*. (Docket ID number EPA–HQ–OPP–2007–0115). Interregional Research Project Number 4 (IR–4), 500 College Road East, Suite 201 W, Princeton, NJ 08540, proposes to establish a tolerance for residues of the fungicide boscalid, (BAS 510F), 3-pyridinecarboxamide, 2-chloro-N-(4'-chloro(1,1'-biphenyl)-2-yl) in or on food commodities avocado at 1.5 ppm; sapote, black at 1.5 ppm; canistel at 1.5 ppm; sopote, mamey at 1.5 ppm; mango at 1.5 ppm; papaya at 1.5 ppm; sapodilla at 1.5 ppm; star apple at 1.5 ppm; and herbs, fresh, subgroup 19A at 60.0 ppm. In plants the parent residue is extracted using an aqueous organic solvent mixture followed by liquid/liquid partitioning and a column clean-up. Quantitation is by GC using MS. In livestock the residues are extracted with methanol. The extract is treated with enzymes in order to release the conjugated glucuronic acid metabolite. The residues are then isolated by liquid/liquid partition followed by column chromatography. The hydroxylated metabolite is acetylated followed by a column clean-up. The parent and acetylated metabolite are quantitated by GC with electron capture detection. Contact: Shaja R. Brothers, telephone number: (703) 308–3194; e-mail address: *brothers.shaja@epa.gov*.

3. *PP 6E7168*. (Docket ID number EPA–HQ–OPP–2007–0114). Interregional Research Project Number 4 (IR–4), 500 College Road East, Suite 201 W, Princeton, NJ 08540, proposes to establish a tolerance for residues of fluroxypyr MHE, and its metabolite fluroxypyr (expressed as combined residues of total fluroxypyr) in or on food commodities pome, fruit, group 11 at 0.02 ppm; millet, grain at 0.5 ppm; millet, forage at 12.0 ppm; grass, hay at 20.0 ppm; millet, proso, grain at 0.5 ppm; millet, proso, straw at 12.0 ppm; millet, proso, forage at 12.0 ppm; millet, proso, hay at 20.0 ppm; millet, pearl, grain at 0.5 ppm; millet, pearl, forage at 12.0 ppm; and millet, pearl, hay at 20.0 ppm. Adequate enforcement method for the combined residues of total fluroxypyr is available to enforce the tolerance expression in or on food. The analytical method uses capillary GC and mass selective detection (MSD) with LOQ of 0.01 ppm. Fluroxypyr has also been tested through the Food and Drug Administration (FDA), Multi-residue Methodology, Protocols C, D, and E. The results have been published in the FDA Pesticide Analytical Manual, volume 1. Contact: Shaja R. Brothers, telephone number: (703) 308–3194; e-mail address: *brothers.shaja@epa.gov*.

Amended Exemption from Tolerance

PP 5E6996. (Docket ID number EPA–HQ–OPP–2005–0306). BASF Corporation, 100 Campus Drive, Florham Park, NJ 07932, proposes to amend an exemption from the requirement of a tolerance for residues of vitamin E (CAS no. 1406–18–4) by including the form of vitamin E alcohol (d-alpha tocopherol, CAS no. 59–02–9 and dl-alpha tocopherol, CAS no. 10191–41–0), and vitamin E Acetate (d-alpha tocopheryl acetate, CAS no. 58–95–7 and dl-alpha tocopheryl acetate, CAS no. 7695–91–2), in or on raw agricultural commodities when used as an ingredient in pesticide formulations used in accordance with good agricultural practices. Vitamin E is a chemical complex that includes eight naturally occurring homologues having a chromanol ring and a twelve-carbon aliphatic side chain containing two methyl groups in the middle and two or more methyl groups on the end. Vitamin E is found in many plant-derived foods and is believed to be necessary for human health. Vitamin E alcohol in the form of d-alpha tocopherol has the highest biological activity of the compounds in the vitamin E complex. Vitamin E alcohol and its ester, vitamin E acetate, are commonly consumed as dietary supplements. Vitamin E alcohol and vitamin E acetate are common food additives. Vitamin E alcohol is used as an antioxidant for foods or food chemicals. Vitamin E acetate is a common animal feed additive and is used widely in topical skin care products.

EPA has determined that the petition contains data or information regarding the elements set forth in section 408 (d)(2) of the FFDCA; however, EPA has not fully evaluated the sufficiency of the submitted data at this time or whether

the data supports granting of the petition. Additional data may be needed before EPA rules on the petition. Because this petition is a request for an exemption from the requirement of a tolerance without numerical limitations, no analytical method is required. Contact: Kathleen Martin, telephone number: (703) 308–2857; e-mail address: *martin.kathleen@epa.gov*.

List of Subjects

Environmental protection, Agricultural commodities, Feed additives, Food additives, Pesticides and pests, Reporting and recordkeeping requirements.

Dated: March 22, 2007.

Donald R. Stubbs,

Acting Director, Registration Division, Office of Pesticide Programs.

[FR Doc. E7–6047 Filed 4–3–07; 8:45 am]

BILLING CODE 6560–50–S

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2007–0018; FRL–8114–3]

Ethylene Oxide; Receipt of Application for Emergency Exemption, Solicitation of Public Comment

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: EPA has received a quarantine exemption request from the United States Department of Agriculture (USDA) to use the pesticide ethylene oxide (EtO); Receipt (CAS No. 75–21–8) to sterilize the interior surfaces of enclosed animal isolator units to control microorganisms to create a germ free environment for research at USDA National Veterinary Services laboratories (NVSL) and at the National Animal Disease Center (NADC) in Ames, IA. The application proposes the use of a pesticide containing an active ingredient which is the subject of a Special Review. Due to the urgent nature of the emergency and the very narrow and extremely limited use being requested, EPA has eliminated the public comment period. Nonetheless, interested parties may still contact the Agency with comments about this notice and treatment program.

DATES: Comments must be received on or before May 4, 2007.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPP–2007–0018 by one of the following methods:

- *Federal eRulemaking Portal*: *http://www.regulations.gov*. Follow the on-line instructions for submitting comments.
- *Mail*: Office of Pesticide Programs (OPP) Regulatory Public Docket (7502P), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001.
- *Delivery*: OPP Regulatory Public Docket (7502P), Environmental Protection Agency, Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. Deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays). Special arrangements should be made for deliveries of boxed information. The Docket telephone number is (703) 305–5805.

Instructions: Direct your comments to docket ID number EPA–HQ–OPP–2007–0018. EPA's policy is that all comments received will be included in the docket without change and may be made available on-line at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through regulations.gov or e-mail. The Federal regulations.gov website is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through regulations.gov, your e-mail address will be automatically captured and included as part of the comment that is placed in the docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the docket index available in regulations.gov. To access the electronic docket, go to *http://www.regulations.gov*, select ''Advanced Search,'' then ''Docket Search.'' Insert the docket ID number where indicated and select the ''Submit'' button. Follow the instructions on the regulations.gov web site to view the docket index or access available documents. Although listed in the index, some information is not publicly available, e.g., 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 either in the electronic docket at *http://www.regulations.gov*, or, if only available in hard copy, at the OPP Regulatory Public Docket in Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. The hours of operation of this Docket Facility are from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The Docket telephone number is (703) 305–5805.

FOR FURTHER INFORMATION CONTACT: Princess Campbell, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: (703) 308–8033; fax number: (703) 308–5433; e-mail address: *campbell.princess@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. Potentially affected entities may include, but are not limited to:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

This listing is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in this unit could also be affected. The North American Industrial Classification System (NAICS) codes have been provided to assist you and others in determining whether this action might apply to certain entities. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed under **FOR FURTHER INFORMATION CONTACT**.

B. What Should I Consider as I Prepare My Comments for EPA?

1. *Submitting CBI.* Do not submit this information to EPA through www.regulations.gov or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for preparing your comments.* When submitting comments, remember to:

i. Identify the document by docket ID number and other identifying information (subject heading, **Federal Register** date and page number).

ii. Follow directions. The Agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

iii. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

iv. Describe any assumptions and provide any technical information and/or data that you used.

v. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

vi. Provide specific examples to illustrate your concerns and suggest alternatives.

vii. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

viii. Make sure to submit your comments by the comment period deadline identified.

II. Background

What Action is the Agency Taking?

Under section 18 of the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) (7 U.S.C. 136p), at the discretion of the Administrator, a Federal or State agency may be exempted from any provision of FIFRA if the Administrator determines that emergency conditions exist which require the exemption. USDA has requested the Administrator to issue a quarantine exemption for the use of EtO on the interior surfaces of enclosed animal isolator units to inactivate forms of microbial life in an inanimate environment, including all forms of vegetative bacteria, bacterial spores, fungi, fungal spores, and viruses to create a germ free environment for animal research. Information in accordance with 40 CFR part 166 was submitted as part of this request.

As part of this request, the Applicant asserts that there are no control products labeled for this use on animal isolator units which could provide the degree of sterilization required for the conduct of this research. Without the ability to sterilize the animal isolator units, NVSL and NADC would not be able to conduct studies of national importance.

The Applicant proposes to make no more than 20 applications of the chemical per year, using the EPA registered product Oxyfume® 2002 ethylene oxide sterilant (a blend of 10% ethylene oxide; 90% refrigerant gas), to sterilize a maximum of nine tub isolators for pigs, nine auxiliary isolators that attach to the tub isolators for pigs, two tub isolators for calves and two auxiliary isolators that attach to the tub isolators for calves. A total of five pounds of the chemical mixture will be used to sterilize each animal isolator unit for a maximum of 1,000 lbs of Oxyfume® 2002 per year. A maximum of 100 lbs a.i. will be applied per year. The chemical will be used to sterilize the animal isolator units on an as needed basis to conduct research at NVSL and NADC over the period for which the quarantine exemption will be granted (3 years).

The regulations governing section 18 of FIFRA require publication of a Notice of Receipt of an application for a quarantine exemption under certain circumstances. The applicant proposes the use of a pesticide containing an active ingredient which is the subject of a Special Review and that is one of the criteria for preparing a Notice of Receipt for certain emergency exemption requests (40 CFR 166.24). As noted above, the Agency has eliminated the comment period due to the urgent nature of the emergency situation and the very narrow and extremely limited use being requested. Nonetheless, interested parties may still contact the Agency with comments about this notice and treatment program.

List of Subjects

Environmental protection, Pesticides and pests.

Dated: March 27, 2007.

Daniel J. Rosenblatt,

Acting Director, Registration Division, Office of Pesticide Programs.

[FR Doc. E7–6249 Filed 4–3–07; 8:45 am]

BILLING CODE 6560–50–S

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2007–0204; FRL–8120–9]

Potential Effects of Atrazine on Amphibian Gonadal Development

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In October 2007, EPA will make a presentation to the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) Scientific Advisory Panel (SAP) concerning EPA's evaluation of the scientific research investigating whether exposure to the herbicide atrazine potentially affects amphibian gonadal development. The scientific research will include studies that were conducted by Syngenta Crop Protection, Inc. in 2005 and 2006 as well as published open literature studies. The notice identifies the open literature studies that EPA has reviewed and requests public comment to ensure that the list of publications is complete. The studies that have been reviewed focus on testing atrazine alone and only on atrazine's potential effects on amphibian gonadal development.

DATES: Comments must be received on or before May 4, 2007.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPP–2007–0204, by one of the following methods:

• *Federal eRulemaking Portal*: *http://www.regulations.gov*. Follow the on-line instructions for submitting comments.

• *Mail*: Office of Pesticide Programs (OPP) Regulatory Public Docket (7502P), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001.

• *Delivery*: OPP Regulatory Public Docket (7502P), Environmental Protection Agency, Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. Deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays). Special arrangements should be made for deliveries of boxed information. The Docket telephone number is (703) 305–5805.

Instructions: Direct your comments to docket ID number EPA–HQ–OPP–2007–

0204. EPA's policy is that all comments received will be included in the docket without change and may be made available on-line at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through regulations.gov or e-mail. The Federal regulations.gov website is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through regulations.gov, your e-mail address will be automatically captured and included as part of the comment that is placed in the docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the docket index available in regulations.gov. To access the electronic docket, go to *http://www.regulations.gov*, select ''Advanced Search,'' then ''Docket Search.'' Insert the docket ID number where indicated and select the ''Submit'' button. Follow the instructions on the regulations.gov web site to view the docket index or access available documents. Although listed in the index, some information is not publicly available, e.g., 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 either in the electronic docket at *http://www.regulations.gov*, or, if only available in hard copy, at the OPP Regulatory Public Docket in Rm. S–4400, One Potomac Yard (South Bldg.), 2777 S. Crystal Dr., Arlington, VA. The hours of operation of this Docket Facility are from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The Docket telephone number is (703) 305–5805.

FOR FURTHER INFORMATION CONTACT: Thomas Steeger, Environmental Fate and Effects Division, Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: 703–305–5444; fax number: 703–305–7695; e-mail address: *steeger.thomas@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

This action is directed to the public in general, and may be of particular interest to those persons who hold or seek registrations of pesticide products containing atrazine under FIFRA. This action may also be of particular interest to those who have published research regarding the potential effects of atrazine on amphibian gonadal development. Since other entities may also be interested, EPA has not attempted to describe all the specific entities that may be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed under **FOR FURTHER INFORMATION CONTACT.**

B. What Should I Consider as I Prepare My Comments for EPA?

When submitting comments identifying additional open literature studies that should be reviewed by EPA, commentors should provide a complete citation following the format of the studies listed in this notice. If possible, a copy of the open literature study should be submitted as well.

II. Background

A. What Action is the Agency Taking?

In April 2002, EPA completed a revised science chapter that characterized the ecological effects of atrazine in support of an Interim Reregistration Eligibility Decision (IRED). At about the same time, scientific articles were published regarding the potential effects of atrazine on amphibian gonadal development, and concerns were raised that EPA had not sufficiently accounted for these data in its risk assessment. In response to an amended consent decree between EPA and the Natural Resources Defense Council (NRDC), EPA issued an atrazine IRED in January 31, 2003 which stipulated that EPA would issue a revised IRED by October 31, 2003. The revised IRED would incorporate recommendations and comments from a FIFRA Scientific Advisory Panel (SAP) regarding studies, submitted by February 28, 2003, on the potential effects of atrazine on amphibians. EPA also agreed to develop a paper, at least three months prior to signing this revised IRED, and submit it to the SAP for review and comment.

In accordance with the consent decree, EPA conducted an extensive review of open literature and registrant-submitted studies concerning the potential effects of atrazine on amphibian gonadal development. After a thorough assessment of all of these studies, EPA concluded there was sufficient information to hypothesize that atrazine exposure can result in effects on amphibian gonadal development, but there was insufficient evidence to refute or confirm that hypothesis because the collective studies failed to show that atrazine produced consistent, reproducible effects across the range of exposure concentrations and amphibian species tested in the studies. EPA summarized the studies and its evaluation of the studies in a White Paper and presented its analysis, conclusions, and recommendations to the SAP during a meeting held on June 17 – 20, 2003.

The SAP concurred with EPA's interpretation of the available data and with EPA's recommendations to seek additional data. Additionally, the SAP concurred with the study approach described in the White Paper for addressing uncertainties identified in the available studies. (For further information regarding this SAP meeting and to obtain a copy of the White Paper and the SAP's report, refer to *http://www.epa.gov/scipoly/sap/meetings/2003/index.htm#061703*.)

In response to the uncertainties identified in the White Paper and based on the recommendations made by the SAP, EPA issued a Data Call-in Notice (DCI) on November 12, 2004, to Syngenta Crop Protection, Inc. (Syngenta) and other atrazine registrants. The DCI required amphibian studies be conducted to determine if exposure to atrazine can affect amphibian gonadal development. Secondary objectives of these studies were to provide information on the repeatability of previous observations, to develop a sound dose-response relationship, and to determine the developmental sensitivity of the amphibian species that are being tested. Syngenta has initiated the studies according to EPA-approved protocols and expects to submit the final study results to EPA in 2007.

On October 9 -12, 2007, EPA will return to the SAP with a second White

Paper discussing the results of Syngenta's amphibian studies conducted in 2005 - 2006. In addition, EPA has continued to review the open literature studies investigating whether atrazine exposure affects amphibian gonadal development. For this second SAP meeting, EPA plans to include only those studies that tested atrazine alone and examined atrazine's potential effects on amphibian gonadal development. Studies on mixtures of pesticides that include atrazine as well as studies of the potential for atrazine to cause adverse effects other than or in addition to amphibian gonadal development are not being considered for the SAP meeting.

In this Federal Register Notice, EPA is soliciting public comment on the completeness of its list of open literature studies on the potential effects of atrazine on amphibian gonadal development. If other publications relevant to these potential effects are available and have not been included in this list, EPA requests that citations be submitted during the comment period. If possible, a copy of the publication should be submitted as well.

EPA has reviewed the following list of relevant open literature studies in preparation for the October SAP meeting:

1. Coady K.K., Murphy M.B., Villeneuve D.L., Hecker M., Jones P.D., Carr J.A., Solomon K.R., Smith E.E., Van der Kraak G., Kendall R.J., and J.P. Giesy. 2004. Effects of Atrazine on Metamorphosis, Growth, Laryngeal and Gonadal Development, Aromatase Activity, and Plasma Sex Steroid Concentrations in Xenopus laevis. Ecotoxicology and Environmental Safety 62:160–173. MRID 458677–04.

2. Coady K.K., Murphy M.B., Villeneuve D.L., Hecker M., Jones P.D., Carr J.A., Solomon K.R., Smith E.E., Van der Kraak G., Kendall R.J., and J.P. Giesy. 2004. Effects of Atrazine on Metamorphosis, Growth, and Gonadal Development in the Green Frog (Rana clamitans). Journal of Toxicology and Environmental Health, Part A, 67: 941–957. MRID 458677–03.

3. DuPreez L.H., Solomon K.R., Carr J.A., Giesy J.P., Gross C., R. J. Kendall et al. 2005. Population Structure Characterization of Clawed Frog (Xenopus laevis) in Corn-growing Versus Non-corn-growing Areas in South Africa. African Journal of Herpetology. 54: 61 – 68.

4. Freeman, J.L. and A.L. Rayburn. 2005. Developmental Impact of Atrazine on Metamorphing Xenopus laevis as Revealed by Nuclear Analysis and Morphology. Environmental Toxicology and Chemistry 24(7): 1648 – 1653.

5. Forson, D. and A. Storfer. 2005. Effects of Atrazine and Iridovirus Infections on Survival and Life-history Traits of the Long-toed Salamander (Ambystoma macrodactylum). Environmental Toxicology and Chemistry 25(1): 168 – 173.

6. Hayes, T.B. 2004. There is No Denying This: Defusing the Confusion about Atrazine. Bioscience 54: 1138 – 1149.

7. Hayes, T.B. 2005. Comment on ''Gonadal Development of Larval Male Xenopus laevis Exposed to Atrazine in Outdoor Microcosms.'' Environmental Science and Technology 39(19) 7757–7758.

8. Hayes, T.B. 2005. Welcome to the Revolution: Integrative Biology and Assessing the Impact of Endocrine Disruptors on Environmental and Public Health. Journal of Integrative and Comparative Biology 45: 321–329.

9. Hayes T.B., Stuart A.A., Mendoza M., Collins A., Noriega N., Vonk A., Johnston W., Liu R., and D. Kpodzo. 2006. Characterization of Atrazine-Induced Gonadal Malformations in African Clawed Frogs (Xenopus laevis) and Comparisons with Effects of an Androgen Antagonist (Cyproterone Acetate) and Exogenous Estrogen (17-β-estradiol): Support for the Demasculinization/Feminization Hypothesis. Environmental Health Perspectives 114: 134 – 141.

10. Jooste A.M., Du Preez L.H., Carr J.A., Giesy J.P., Gross T.S., Kendall R.J., Smith E.E., Van Der Kraak G.J., and K.R. Solomon. 2004. Gonadal Development of Larval Male Xenopus laevis Exposed to Atrazine in Outdoor Microcosms. Environmental Science and Technology 39: 5255–5261. MRID 458677.

11. Murphy M.B., Hecker M., Coady K.K., Tompsett A.R., Jones,P.D., DuPreez L.H., Solomon K.R., Carr J.A., Smith, E.E., Kendall R.J., van der Kraak G., and J.P. Giesy. 2005. Sediment TCDD-Eq's and EROD and MROD Activities in Ranid Frogs from Agricultural and Non-agricultural Sites in Michigan (USA). Archives of Environmental Contamination and Toxicology 51(3): 467–477. MRID 458677–02.

12. Murphy, M.B, Hecker M., Coady K.K., Tompsett A.R., DuPreez L.H., Everson G.J., Solomon K.R., Carr J.A., Smith E.E., Kendall R.J., van der Kraak G., and J.P. Giesy. 2005. Atrazine Concentrations, Gonadal Gross Morphology, and Histology in Ranid Frogs Collected in Michigan Agricultural Areas. Aquatic Toxicology 76: 230–245. MRID 458677–02.

13. Murphy, M. B., Hecker M., Coady K.K., Tompsett A.R., Higley E.B., Jones P.D., Du Preez L.H., Solomon K.R., Carr J.A., Smith E.E., Kendall R.J., Van Der Kraak G., and J. P. Giesy. 2006. Plasma Steroid Hormone Concentrations, Aromatase Activities and GSI in Ranid Frogs Collected from Agricultural and Non-Agricultural Sites in Michigan (USA). Aquatic Toxicology 77: 153 – 166.

14. Orton, F., Carr J.A., and R. D. Handy. 2006. Effects of Nitrate and Atrazine on Larval Development and Sexual Differentiation in the Northern Leopard Frog Rana pipiens. Environmental Toxicology and Chemistry 25(1): 65 – 71.

15. Smith E.E., Du Preez L.H., Gentles B.A., Solomon K.R., Tandler B., Carr J.A., Van Der Kraak G.J., Kendall R.J., Giesy J.P. and Gross T.S. 2005. Assessment of Laryngeal Muscle and Testicular Cell Types in Xenopus laevis (Anura Pipidae) Inhabiting Maize and Non-maize Growing Areas of South Africa. African Journal of Herpetology 54(1): 69–76. MRID 458677–10.

16. Sullivan K. B, and K. M. Spence. 2003. Effects of Sublethal Concentrations of Atrazine and Nitrate on Metamorphosis of the African Clawed Frog. Environmental Toxicology and Chemistry 22(3): 627 – 635.

B. What is the Agency's Authority for Taking this Action?

EPA is taking action under 7 U.S.C. 136b of the FIFRA.

List of Subjects

Environmental protection, atrazine, amphibian gonadal development.

Dated: March 29, 2007.

Steve Bradbury,

Director, Environmental Fate and Effects Division

[FR Doc. E7–6253 Filed 4–3–07; 8:45 am]

BILLING CODE 6560–50–S

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) Being Submitted for Review to the Office of Management and Budget

March 27, 2007.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection(s), as required by the Paperwork Reduction Act (PRA) of 1995, Pub. L. 104–13. An agency may not conduct or sponsor a collection of information unless it

displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (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 burden estimate; (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 the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Written Paperwork Reduction Act (PRA) comments should be submitted on or before May 4, 2007. If you anticipate that you will be submitting PRA comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the FCC contact listed below as soon as possible.

ADDRESSES: Direct all PRA comments to Jasmeet K. Seehra, Office of Management and Budget, Room 10236 NEOB, Washington, DC 20503, (202) 395–3123, or via fax at 202–395–5167 or via Internet at *Jasmeet_K._Seehra@omb.eop.gov* and to *Judith-B. Herman@fcc.gov*, Federal Communications Commission, Room 1–B441, 445 12th Street, SW., Washington, DC 20554 or an e-mail to *PRA@fcc.gov.* If you would like to obtain or view a copy of this information collection, you may do so by visiting the FCC PRA Web page at: *http://www.fcc.gov/omd/pra.*

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collection(s), contact Judith B. Herman at 202–418–0214 or via the Internet at *Judith-B.Herman@fcc.gov.*

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–1067.

Title: Qualification Questions.

Form No.: FCC Form 312–EZ.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for-profit.

Number of Respondents: 3,872 respondents; 38,720 responses.

Estimated Time Per Response: 10 hours.

Frequency of Response: On occasion reporting requirement.

Obligation to Respond: Required to obtain or retain benefits.

Total Annual Burden: 38,720 hours.

Total Annual Cost: $9,874,000.

Privacy Act Impact Assessment: N/A.

Nature and Extent of Confidentiality: There is no need for confidentiality.

Needs and Uses: The Commission will submit this information collection to OMB as an extension during this comment period to obtain the full three-year clearance from them. There is no change in the number of respondents, burden hours or annual costs.

The FCC Form 312–EZ, Qualification Questions, is used by applicants for the C-band and Ku-band earth stations (non-common carrier applicants) who are eligible for the ''auto-grant'' procedure. Under the ''auto-grant process'' the International Bureau of the FCC automatically grants ''routine'' earth station applications proposing to use the C-band or Ku-band. To be considered ''routine'', earth station must meet a number of requirements, including primarily the following: (1) The earth station antenna must meet certain minimum diameter requirements; (2) the proposed earth station must meet the antenna performance standard and power limitations contained in Part 25 of the Commission's rules; (3) the earth station must be coordinated as required by Part 25; (4) the applicant seeks to communicate only with satellites authorized to provide service in the United States; and (5) the proposed station is otherwise consistent with the Commission's legal requirements.

This information collection is used by Commission staff in carrying out its duties concerning satellite communications as required by Sections 301, 308, 309, and 310 of the Communications Act of 1934, as amended. It is also used by the Commission staff in carrying out its duties under the World Trade Organization (WTO) Basic Telecom Agreement. Without such information, the Commission could not determine whether to permit respondents to provide telecommunications services in the United States.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. E7–6154 Filed 4–3–07; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) Being Reviewed by the Federal Communications Commission, Comments Requested

March 28, 2007.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection(s), as required by the Paperwork Reduction Act (PRA) of 1995, Public Law No. 104–13. An agency may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act that does not display a valid control number. Comments are requested concerning (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 burden estimate; (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 the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Written Paperwork Reduction Act (PRA) comments should be submitted on or before June 4, 2007. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: You may submit all your Paperwork Reduction Act (PRA) comments by e-mail or U.S. postal mail. To submit your comments by e-mail send them to *PRA@fcc.gov.* To submit your comments by U.S. mail, mark them to the attention of Cathy Williams, Federal Communications Commission, Room 1–C823, 445 12th Street, SW., Washington, DC 20554 and Jasmeet Seehra, OMB Desk Officer, Office of Management and Budget (OMB), Room 10236 NEOB, 725 17th Street, NW., Washington, DC 20503 or via Internet at *Jasmeet_K._Seehra@omb.eop.gov* or via fax at (202) 395–5167.

FOR FURTHER INFORMATION CONTACT: For additional information about the information collection(s) send an e-mail to *PRA@fcc.gov* or contact Cathy Williams at (202) 418–2918.

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–0937.

Title: Establishment of a Class A Television Service, MM Docket No. 00–10.

Form Number: Not applicable.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for-profit entities.

Number of Respondents: 560.

Estimated Time per Response: 0.017 hours–52 hours.

Frequency of Response: Recordkeeping requirement; On occasion reporting requirement; Quarterly reporting requirement; Third party disclosure requirement.

Total Annual Burden: 261,908 hours.

Total Annual Cost: $1,295,500.

Nature of Response: Required to obtain or retain benefits.

Privacy Impact Assessment: No impact(s).

Confidentiality: There is no need for confidentiality with this collection of information.

Needs and Uses: On November 29, 1999, the Community Broadcasters Protection Act of 1999 (CBPA), Pub. L. No. 106–113, 113 Stat. Appendix I at pp. 1501A–594—1501A–598 (1999), codified at 47 U.S.C. Section 336(f), was enacted. That legislation provided that a low power television (LPTV) licensee should be permitted to convert the secondary status of its station to the new Class A status, provided it can satisfy certain statutorily-established criteria. The CBPA directs that Class A licensees be subject to the same license terms and renewal standards as full-power television licenses and that Class A licensees be accorded primary status as television broadcasters as long as they continue to meet the requirements set forth in the statute for a qualifying low power station. The CBPA sets out certain certification and application procedures for LPTV licensees seeking Class A designation, prescribes the criteria LPTV licensees must meet to be eligible for Class A licenses, and outlines the interference protection Class A applicants must provide to analog, digital, LPTV and TV translator stations.

The CBPA directs that Class A stations must comply with the operating requirements for full-service television broadcast stations. Therefore, beginning on the date of its application for a Class A license and thereafter, a station must be ''in compliance'' with the Commission's operating rules for full-service television stations, contained in 47 CFR part 73.

Federal Communications Commission.

William F. Caton,

Deputy Secretary.

[FR Doc. E7–6156 Filed 4–3–07; 8:45 am]

BILLING CODE 6712–10–P

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) Being Reviewed by the Federal Communications Commission for Extension Under Delegated Authority

March 28, 2007.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden, invites the general public and other Federal agencies to take this opportunity to comment on the following information collection(s), as required by the Paperwork Reduction Act (PRA) of 1995, Public Law No. 104–13. An agency may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act that does not display a valid control number. Comments are requested concerning (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 burden estimate; (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 the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Written Paperwork Reduction Act (PRA) comments should be submitted on or before June 4, 2007. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: You may submit all your Paperwork Reduction Act (PRA) comments by e-mail or U.S. postal mail. To submit your comments by e-mail send them to *PRA@fcc.gov*. To submit your comments by U.S. mail, mark them to the attention of Cathy Williams, Federal Communications Commission, Room 1–C823, 445 12th Street, SW., Washington, DC 20554 and Jasmeet Seehra, Desk Officer, Office of Management and Budget (OMB), Room 10236 NEOB, 725 17th Street, NW., Washington, DC 20503 or via Internet at *Jasmeet_K._Seehra@omb.eop.gov* or via fax at (202) 395–5167.

FOR FURTHER INFORMATION CONTACT: For additional information about the information collection(s) send an e-mail to *PRA@fcc.gov* or contact Cathy Williams at (202) 418–2918.

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–1065.

Title: Implementation of Section 25 of the Cable Television Consumer Protection and Competition Act of 1992 Re: DBS Public Interest Obligation; 47 CFR 25.701.

Form Number: Not applicable.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for-profit entities.

Number of Respondents: 15.

Estimated Time per Response: 1 hour–10 hours.

Frequency of Response: Recordkeeping requirement; On occasion reporting requirement; One-time reporting requirement; Annual reporting requirement; Third party disclosure requirement.

Total Annual Burden: 375 hours.

Total Annual Cost: None.

Privacy Impact Assessment: No impact(s).

Nature of Response: Required to obtain or retain benefits.

Confidentiality: No need for confidentiality required.

Needs and Uses: The Commission has vacated an Order on Reconsideration, In the matter of Implementation of Section 25 Of The Cable Television Consumer Protection and Competition Act Of 1992, Direct Broadcast Satellite (DBS) Public Interest Obligations, MM Docket 93–25 FCC 03–78, adopted April 9, 2003 and adopted in its place, in the same proceeding, a Second Order on Reconsideration of the First Report and Order, Sua Sponte Order on Reconsideration (''Second Order'') and accompanying rules FCC 04–44, released March 25, 2004. *The Second Order differs from the Order on Reconsideration with respect to two issues:* (1) The political broadcasting requirements, and (2) the guidelines concerning commercialization of children's programming.

47 CFR 25.701(c)(1)(i)(C) states DBS providers may establish and define their own reasonable classes of immediately preemptible time so long as the differences between such classes are based on one or more demonstrable benefits associated with each class and are not based solely upon price or identity of the advertiser. Such demonstrable benefits include, but are not limited to, varying levels of preemption protection, scheduling flexibility, or associated privileges, such

as guaranteed time sensitive make goods. DBS providers may not use class distinctions to defeat the purpose of the lowest unit charge requirement. All classes must be fully disclosed and made available to candidates.

47 CFR 25.701(c)(1)(i)(D) states DBS providers may establish reasonable classes of preemptible with notice time so long as they clearly define all such classes, fully disclose them and make them available to candidates.

47 CFR 25.701(c)(1)(i)(E) states DBS providers may treat non preemptible and fixed position as distinct classes of time provided that they articulate clearly the differences between such classes, fully disclose them, and make them available to candidates.

47 CFR 25.701(c)(1)(i)(I) states DBS providers shall review their advertising records periodically throughout the election period to determine whether compliance with this section requires that candidates receive rebates or credits. Where necessary, DBS providers shall issue such rebates or credits promptly.

47 CFR 25.701(c)(1)(i)(M) states DBS providers must disclose and make available to candidates any make good policies provided to commercial advertisers. If a DBS provider places a make good for any commercial advertiser or other candidate in a more valuable program or daypart, the value of such make good must be included in the calculation of the lowest unit charge for that program or daypart.

47 CFR 25.701(c)(1)(ii) states at any time other than the respective periods set forth in paragraph (c)(1)(i) of this section, DBS providers may charge legally qualified candidates for public office no more than the charges made for comparable use of the facility by commercial advertisers. The rates, if any, charged all such candidates for the same office shall be uniform and shall not be rebated by any means, direct or indirect. A candidate shall be charged no more than the rate the DBS provider would charge for comparable commercial advertising. All discount privileges otherwise offered by a DBS provider to commercial advertisers must be disclosed and made available upon equal terms to all candidates for public office.

47 CFR 25.701(d) states each DBS provider shall keep and permit public inspection of a complete and orderly political file and shall prominently disclose the physical location of the file, and the telephonic and electronic means to access the file.

(1) *The political file shall contain, at a minimum:*

(i) A record of all requests for DBS origination time, the disposition of those requests, and the charges made, if any, if the request is granted. The ''disposition'' includes the schedule of time purchased, when spots actually aired, the rates charged, and the classes of time purchased; and

(ii) A record of the free time provided if free time is provided for use by or on behalf of candidates.

(2) DBS providers shall place all records required by this section in a file available to the public as soon as possible and shall be retained for a period of four years until December 31, 2006, and thereafter for a period of two years.

47 CFR 25.701(e)(3) requires DBS providers airing children's programming must maintain records sufficient to verify compliance with this rule and make such records available to the public. Such records must be maintained for a period sufficient to cover the limitations period specified in 47 U.S.C. 503(b)(6)(B).

47 CFR 25.701(f)(6) states: In addition to the political file requirements in Sec. 25.701(d), each DBS provider shall keep and permit public inspection of a complete and orderly record of:

(A) Quarterly measurements of channel capacity and yearly average calculations on which it bases its four percent reservation, as well as its response to any capacity changes;

(B) A record of entities to whom noncommercial capacity is being provided, the amount of capacity being provided to each entity, the conditions under which it is being provided and the rates, if any, being paid by the entity;

(C) A record of entities that have requested capacity, disposition of those requests and reasons for the disposition.

(ii) All records required by this paragraph shall be placed in a file available to the public as soon as possible and shall be retained for a period of two years.

Federal Communications Commission.

William F. Caton,

Deputy Secretary.

[FR Doc. E7–6157 Filed 4–3–07; 8:45 am]

BILLING CODE 6712–10–P

FEDERAL COMMUNICATIONS COMMISSION

Federal Advisory Committee Act; Communications Security, Reliability and Interoperability Council

AGENCY: Federal Communications Commission.

ACTION: Notice of intent to establish.

SUMMARY: In accordance with the Federal Advisory Committee Act, the purpose of this notice is to announce that a Federal Advisory Committee, known as the ''Communications Security, Reliability and Interoperability Council'' (hereinafter the ''Council'') is being established.

ADDRESSES: Federal Communications Commission, Public Safety & Homeland Security Bureau, Attn: Lisa M. Fowlkes, 445 12th Street, SW., Room 7–C753, Washington, DC 20554.

FOR FURTHER INFORMATION CONTACT: Lisa M. Fowlkes, Federal Communications Commission, Public Safety & Homeland Security Bureau, 445 12th Street, SW., Room 7–C753, Washington, DC 20554. Telephone: (202) 418–7452, e-mail: *lisa.fowlkes@fcc.gov*.

SUPPLEMENTARY INFORMATION: The Chairman of the Federal Communications Commission has determined that the establishment of the Council is necessary and in the public interest in connection with the performance of duties imposed on the Federal Communications Commission (''FCC'' or ''Commission'') by law. The Committee Management Secretariat, General Services Administration concurs with the establishment of the Council. The purpose of the Council is to provide recommendations to the FCC to ensure optimal security, reliability and interoperability of communications systems, including telecommunications, media and public safety communications systems. This Council will replace the Network Reliability and Interoperability Council (NRIC) and the Media Security and Reliability Council (MSRC). The Council's duties will include: (1) Recommending to the FCC best practices to ensure the security, reliability, operability and interoperability of public safety communications systems; (2) evaluating ways to strengthen the collaboration between communication service providers and public safety agencies during emergencies; (3) recommending to the FCC ways to improve the Emergency Alert System (EAS), including best practices for EAS; (4) recommending to the FCC steps necessary to better prepare for shifts in communications usage patterns that likely would result from a pandemic flu outbreak; (5) recommending to the FCC technologies and systems that can best facilitate the communication of emergency information to and from hospitals, schools, day care facilities and other facilities that provide vital public services; (6) developing and

recommending to the FCC best practices to facilitate the communication of emergency information to the public, including people who do not speak English, individuals with disabilities, the elderly and people living in rural areas; (7) recommending to the FCC methods by which the communications industry can reliably and accurately measure the extent to which key best practices are implemented; (8) reviewing and recommending to the FCC updates of existing NRIC and MSRC best practices; (9) reviewing the deployment of Internet Protocol (IP) as a network protocol for critical next generation infrastructure, including emergency/first responder networks; and (10) reviewing and recommending to the FCC an implementation plan for the ''emergency communications internetwork'' advocated by NRIC VII, Focus Group 1D in its December 2005 Final Report.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. E7–6254 Filed 4–3–07; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL MARITIME COMMISSION

Notice of Agreements Filed

The Commission hereby gives notice of the filing of the following agreements under the Shipping Act of 1984. Interested parties may submit comments on agreements to the Secretary, Federal Maritime Commission, Washington, DC 20573, within ten days of the date this notice appears in the **Federal Register**. Copies of agreements are available through the Commission's Office of Agreements (202–523–5793 or *tradeanalysis@fmc.gov*).

Agreement No.: 011284–061.

Title: Ocean Carrier Equipment Management Association Agreement.

Parties: APL Co. Pte. Ltd.; American President Lines, Ltd.; A.P. Moller-Maersk A/S; CMA CGM, S.A.; Atlantic Container Line, Companhia Libra de Navegacao; Compania Libra de Navegacion Uruguay S.A.; Compania Sudamericana de Vapores, S.A.; COSCO Containerlines Company Limited; Crowley Maritime Corporation; Evergreen Marine Corp. (Taiwan) Ltd.; Hamburg-Süd; Hapag-Lloyd AG; Hapag-Lloyd USA LLC; Hanjin Shipping Co., Ltd.; Hyundai Merchant Marine Co. Ltd.; Kawasaki Kisen Kaisha, Ltd.; Mitsui O.S.K. Lines Ltd.; Nippon Yusen Kaisha Line; Norasia Container Lines Limited; Orient Overseas Container Line Limited; and Yang Ming Marine Transport Corp.

Filing Party: Jeffrey F. Lawrence, Esq. and Donald J. Kassilke, Esq., Sher & Blackwell LLP, 1850 M Street, NW., Suite 900, Washington, DC 20036.

Synopsis: The amendment would change the name of Montemar Maritima S.A., delete Evergreen Marine Corp. (Taiwan) Ltd., and add the Evergreen Line Joint Service Agreement as a party to the agreement.

Agreement No.: 011910–003.

Title: HSDG/APL Space Charter Agreement.

Parties: Hamburg Sud and APL Co. PTE Ltd.

Filing Party: Wayne R. Rohde, Esq., Sher & Blackwell LLP, 1850 M Street, NW., Suite 900, Washington, DC 20036.

Synopsis: The amendment extends the duration of the agreement to on or about April 30, 2007.

Agreement No.: 011962–002.

Title: Consolidated Chassis Management Pool Agreement.

Parties: The Ocean Carrier Equipment Management Association and its member lines; the Association's subsidiary Consolidated Chassis Management LLC and its affiliates; China Shipping Container Lines Co., Ltd.; and Mediterranean Shipping Co., S.A.

Filing Party: Jeffrey F. Lawrence, Esq., Sher & Blackwell LLP, 1850 M Street, NW., Suite 900, Washington, DC 20036.

Synopsis: The amendment would change the name of Montemar Maritima S.A., delete Evergreen Marine Corp. (Taiwan) Ltd., and add the Evergreen Line Joint Service Agreement as a party to the agreement.

Agreement No.: 011968–001.

Title: Hanjin-Evergreen Cross Slot Charter Agreement.

Parties: Evergreen Line Joint Service Agreement (''Evergreen'') and Hanjin Shipping Co., Ltd. (''Hanjin'').

Filing Party: Paul M. Keane, Esq., Cichanowicz, Callan, Keane, Vengrow & Textor, LLP, 61 Broadway, Suite 3000, New York, NY 10006–2802.

Synopsis: This amendment deletes Evergreen Marine Corp. Ltd. and substitutes the Evergreen Line Joint Service Agreement.

Agreement No.: 011992.

Title: EUKOR/NYK Space Charter Agreement.

Parties: EUKOR Car Carriers, Inc. and Nippon Yusen Kaisha.

Filing Party: Wayne R. Rohde, Esq., Sher & Blackwell LLP, 1850 M Street, NW., Suite 900, Washington, DC 20036.

Synopsis: The agreement authorizes EUKOR to charter space to NYK for the carriage of motor vehicles on car carriers between the U.S. and Venezuela.

Agreement No.: 011993.

Title: MSC/APL/MOL Space Charter Agreement.

Parties: Mediterranean Shipping Company S.A.; American President Lines, Ltd and APL Co. Pte. Ltd.; and Mitsui O.S.K. Lines, Ltd.

Filing Party: Wayne R. Rohde, Esq., Sher & Blackwell LLP, 1850 M Street, NW., Suite 900, Washington, DC 20036.

Synopsis: The agreement authorizes MSC to charter space to APL and MOL between the U.S. East Coast and Argentina and Brazil.

By order of the Federal Maritime Commission.

Dated: March 30, 2007.

Bryant L. VanBrakle,

Secretary.

[FR Doc. E7–6250 Filed 4–3–07; 8:45 am]

BILLING CODE 6730–01–P

FEDERAL RESERVE SYSTEM

Change in Bank Control Notices; Acquisition of Shares of Bank or Bank Holding Companies

The notificants listed below have applied under the Change in Bank Control Act (12 U.S.C. 1817(j)) and § 225.41 of the Board's Regulation Y (12 CFR 225.41) to acquire a bank or bank holding company. The factors that are considered in acting on the notices are set forth in paragraph 7 of the Act (12 U.S.C. 1817(j)(7)).

The notices are available for immediate inspection at the Federal Reserve Bank indicated. The notices also will be available for inspection at the office of the Board of Governors. Interested persons may express their views in writing to the Reserve Bank indicated for that notice or to the offices of the Board of Governors. Comments must be received not later than April 18, 2007.

A. Federal Reserve Bank of Dallas (W. Arthur Tribble, Vice President) 2200 North Pearl Street, Dallas, Texas 75201-2272:

1. Belote Family Partnership, Ltd., Kingwood, Texas, and its general partner, Belote Management Trust, and Farrald Belote, Jr. and Arlene Belote, as co–trustees, Kingwood Texas; to retain voting shares of Country Holding Corp., Austin, Texas, and thereby indirectly retain voting shares of Texas Country Bank, Lakeway, Texas.

Board of Governors of the Federal Reserve System, March 29, 2007.

Robert deV. Frierson,

Deputy Secretary of the Board.

[FR Doc. E7–6178 Filed 4–3–07; 8:45 am]

BILLING CODE 6210–01–S

FEDERAL RESERVE SYSTEM

Formations of, Acquisitions by, and Mergers of Bank Holding Companies

The companies listed in this notice have applied to the Board for approval, pursuant to the Bank Holding Company Act of 1956 (12 U.S.C. 1841 *et seq.*) (BHC Act), Regulation Y (12 CFR Part 225), and all other applicable statutes and regulations to become a bank holding company and/or to acquire the assets or the ownership of, control of, or the power to vote shares of a bank or bank holding company and all of the banks and nonbanking companies owned by the bank holding company, including the companies listed below.

The applications listed below, as well as other related filings required by the Board, are available for immediate inspection at the Federal Reserve Bank indicated. The application also will be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing on the standards enumerated in the BHC Act (12 U.S.C. 1842(c)). If the proposal also involves the acquisition of a nonbanking company, the review also includes whether the acquisition of the nonbanking company complies with the standards in section 4 of the BHC Act (12 U.S.C. 1843). Unless otherwise noted, nonbanking activities will be conducted throughout the United States. Additional information on all bank holding companies may be obtained from the National Information Center Web site at *www.ffiec.gov/nic/*.

Unless otherwise noted, comments regarding each of these applications must be received at the Reserve Bank indicated or the offices of the Board of Governors not later than April 30, 2007.

A. Federal Reserve Bank of San Francisco (Tracy Basinger, Director, Regional and Community Bank Group) 101 Market Street, San Francisco, California 94105-1579:

1. Saddleback Bancorp, Tustin, California; to become a bank holding company by acquiring 100 percent of the voting shares of Tustin Community Bank, Tustin, California.

In connection with this application, Applicant also has applied acquire 100 percent of the voting shares of Saddleback Loan Company, Tustin, California, and thereby engage in extending credit and servicing loans, pursuant to section 225.28(b)(1) of Regulation Y.

Board of Governors of the Federal Reserve System, March 30, 2007.

Robert deV. Frierson,

Deputy Secretary of the Board.

[FR Doc. E7–6219 Filed 4–3–07; 8:45 am]

BILLING CODE 6210–01–S

FEDERAL TRADE COMMISSION

Granting of Request for Early Termination of the Waiting Period Under the Premerger Notification Rules

Section 7A of the Clayton Act, 15 U.S.C. 18a, as added by Title II of the Hart-Scott-Rodino Antitrust Improvements Act of 1976, requires persons contemplating certain mergers or acquisitions to give the Federal Trade Commission and the Assistant Attorney General advance notice and to wait designated periods before consummation of such plans. Section 7A(b)(2) of the Act permits the agencies, in individual cases, to terminate this waiting period prior to its expiration and requires that notice of this action be published in the **Federal Register**.

The following transactions were granted early termination of the waiting period provided by law and the premerger notification rules. The grants were made by the Federal Trade Commission and the Assistant Attorney General for the Antitrust Division of the Department of Justice. Neither agency intends to take any action with respect to these proposed acquisitions during the applicable waiting period.

Trans No.	Acquiring	Acquired	Entities
TRANSACTIONS GRANTED EARLY TERMINATION—03/09/2007			
20070617	Arrow Electronics, Inc	Agilysys, Inc	Agilysys.
20070830	TCV V, L.P	TechTarget, Inc	TechTarget Inc.
20070852	USG Corporation	Joseph Zucchero	California Wholesale Material Supply, Inc.; E Foam Corp.; Southwest Install and Rework, Inc.; Stockdale Materials Co., Inc.
20070854	Peak Resorts, Inc	Oak Hill Capital Partners, L.P	L.B.O. Holding, Inc; Mount Snow Ltd.
20070860	Avista Capital Partners, L.P	Invitrogen Corporation	BioReliance Corporation.
20070863	New Mountain Partners II, L.P	Ikaria Holding, Inc	Ikaria Holdings, Inc.
20070864	Eos Capital Partners III, L.P	Victor Grillo, Jr	DTR Advertising. Inc.
20070870	JP Morgan Chase & Co	Western & Southern Mutual Holding Company.	Integrated Investment Services, Inc.
20070873	GGC Investment Fund II, L.P	Blair Corporation	Blair Corporation.
20070875	Comverse Technology, Inc	Witness Systems, Inc	Witness Systems, Inc.
20070893	Kia Motors Corporation	Hyundai Motor Company	Hyundai Motor Finance Company.
TRANSACTIONS GRANTED EARLY TERMINATION—03/12/2007			
20070881	Citigroup, Inc	Srinivasan Subramanian	Caritor, Inc.
20070882	Citigroup, Inc	Keane, Inc	Keane, Inc.
TRANSACTIONS GRANTED EARLY TERMINATION—03/13/2007			
20070807	Constellation Brands, Inc	AlcoFinance S.A	AlcoFi, Inc.
20070824	Weston Presidio V, L.P	TSG4 L.P	PR Holding Corp.; Pureology Research LLC.
20070862	Craig O. McCaw	AT&T Inc	BellSouth Corporation; BellSouth Wireless Cable, Inc.; South Florida Television, Inc.
20070888	Saputo Inc	Land O'Lakes, Inc	Cheese & Protein International LLC.
200070892	TA X L.P	Alere Medical Incorporated	Alere Medical Incorporated.

Trans No.	Acquiring	Acquired	Entities
20070899	PetSmart, Inc	MMI Holdings, Inc	MMI Holdings, Inc.
TRANSACTIONS GRANTED EARLY TERMINATION—03/14/2007			
20070869	EXCO Resources, Inc	Anadarko Petroleum Corporation	Anardarko E&P Company LP; Howell Petroleum Corporation; Kerr-McGee Oil & Gas Onshore LP.
20070884	Coleman Cable, Inc	Spell Capital Partners Fund I, L.P	Spell Capital Corporation.
TRANSACTIONS GRANTED EARLY TERMINATION—03/15/2007			
20070596	LodgeNet Entertainment Corporation	Liberty Media Corporation	Ascent Entertainment Group, Inc.
20070865	Nestle S.A	ZARS, Inc	ZARS, Inc.
20070866	L'Oreal S.A	ZARS, Inc	ZARS, Inc.
TRANSACTIONS GRANTED EARLY TERMINATION—03/19/2007			
20070902	Landmark Communications, Inc	Siegel Enterprises, Inc	Eneighborhoods, Inc.; Home Data Corporation; RECHANNEL Communications, Inc.; Siegel Enterprises, Inc.; Wyld Acquisition Corp.
TRANSACTIONS GRANTED EARLY TERMINATION—03/20/2007			
20070826	Cougard Holding	Compagnie de Saint-Gobain	Saint-Gobain Desjonqueres.
20070845	Atlas Copco AB	Dynapac Group AB	Dynapac Group AB.
20070900	Encore Acquisition Corporation	Anadarko Petroleum Corporation	Clear Fork Pipeline Company; Howell Petroleum Corporation; Kerr-McGee Oil & Gas Onshore LP.
20070903	Powdr Corporation	Oak Hill Capital Partners, L.P	Cherry Knoll Associates, LLC; Killington, Ltd.; Killington Restaurants, Inc.; Pico Ski Area Management Company.
20070906	Ronald O. Perelman	M & F Worldwide Corp	M & F Worldwide Corp.
20070907	MidOcean Partners III, L.P	Lehman Brothers Merchant Banking Partners III, L.P.	Hunter Fan Holdings, Inc.
20070911	Commercial Metals Company	Nicholas J. Bouras	ABA Trucking Corporation; Bouras Industries, Inc.; Nicholas J. Bouras, Inc.; The New Columbia Joist Company; United Steel Deck, Inc.
20070912	Payless Shoesource, Inc	Sunrise Capital Partners, L.P	Collective International, LP.
20070918	Otsuka Pharmaceutical Co., Ltd	GW Pharmaceuticals plc	GW Pharma Ltd.
20070919	Shidax Corporation	The Smith & Wollensky Restaurant Group, Inc.	The Smith & Wollensky Restaurant Group, Inc.
20070920	GS Capital Partners VI, L.P	Michael I.M. MacMillan	Entertainment Holdco; Movie Holdco.
20070921	Colony Investors VIII, L.P	Station Casinos, Inc	Station Casinos, Inc.
20070923	Trident IV, L.P	Ford Motor Company	Automobile Protection Corporation.
20070926	GS Capital Partners VI, L.P	Seaton McLean	Entertainment Holdco; Movie Holdco.
20070930	JDS Uniphase Corporation	Picolight Incorporated	Picolight Incorporated.
20070939	Court Square Capital Partners II, L.P	JLL Partners Fund IV, L.P	Mosaic Sales Solutions Holding Co.
20070943	Ares Corporate Opportunities Fund II, L.P.	EXCO Resources, Inc	EXCO Resources, Inc.
TRANSACTIONS GRANTED EARLY TERMINATION—03/21/2007			
20070891	FS Acquisition Corp	Isadore Sharp	Four Seasons Hotels Inc.
20070914	Alstom, SA	Calpine Corporation	Power Systems MFG, LLC.
TRANSACTIONS GRANTED EARLY TERMINATION—03/22/2007			
20070384	The Men's Wearhouse, Inc	Federated Department Stores, Inc	After Hours Formalwear, Inc.
20070885	Micron Technology, Inc	TECH Semiconductor Singapore Pte. Ltd.	TECH Semiconductor Singapore Pte. Ltd.
20070894	Citigroup Inc	Seton House Group Limited	Public Safety Luxembourg S.a.r.l.
20070917	National Oilwell Varco, Inc	Gammaloy Holdings, L.P	Gammaloy Holdings, L.P.
TRANSACTIONS GRANTED EARLY TERMINATION—03/23/2007			
20070365	Applied Materials, Inc	Brooks Automation, Inc	Brooks Automation, Inc.
20070890	Eli Lilly and Company	Hypnion, Inc	Hypnion, Inc.
20070916	AIF VI Euro Holdings, LP, c/o Apollo Management Intl. LLP.	Oceania Cruise Holdings, Inc	Oceania Cruise Holdings, Inc.
20070922	Pouschine Cook Capital Partners II, LP.	Crownline Boats, Inc	Crownline Boats, Inc.

Trans No.	Acquiring	Acquired	Entities
20070928	Aktiegolaget Volvo	Ingersoll-Rand Company Limited	Blaw-Knox Construction Equipment Corporation.
20070932	Beacon Roofing Supply, Inc	North Coast Commercial Roofing Systems, Inc.	North Coast Commercial Roofing Systems, Inc.
20070940	OCM Principal Opportunities Fund IV, IL.P.	EXCO Resources, Inc	EXCO Resources, Inc.
20070944	OCM Opportunities Fund VII, L.P	EXCO Resources, Inc	EXCO Resources, Inc.
20070949	Ambassadors international, Inc	Carnival Corporation	Windstar Sail Cruises Limited.
20070950	AP Berry Holdings, LLC	Berry Plastics Group, Inc	Berry Plastics Group, Inc.
20070951	Vestar Capital Partners V, L.P	Paul Danton (Dan) Huish	Huish Detergents, Inc.
20070952	Graham Partners II, L.P	Berry Plastics Group, Inc	Berry Plastics Group, Inc.
20070953	Apollo Investment Fund VI, L.P	Berry Plastics Group, Inc	Berry Plastics Group, Inc.
20070954	Apollo Investment Fund V, L.P	Apollo Investment Fund VI, L.P	Berry Plastics Group, Inc.
20070968	Iconix Brand Group, Inc	ROCSAN Holdings, LLC	ROCAWEAR LICENSING, LLC.
20070970	John D. Baker II	Holdco	Holdco.
20070971	Monomoy Capital Partners, L.P	Global Home Products LLP, Chapter 11 debtor in possession.	Anchor Hocking CG Operating Company, LLC; Anchor Hocking Operating Company, LLC, Anchor Hocking Operating Company LLC.
20070974	Zurich Financial Services	Bristol West Holdings, Inc	Bristol West Holdings, Inc.
20070975	IDB Holding Corporation Ltd	Susan W. Shoval	Guard Financial Group, Inc.
20070977	LPL Investment Holdings, Inc	Pacific Mutual Holding Company	Pacific Select Group LLC.
20070982	Spire Capital Partners II, L.P	Professional Bull Riders, Inc	Professional Bull Riders, Inc.
20070984	Marathon Special Opportunity Master Fund, Ltd.	SPX Corporation	General Signal UK Ltd.
20070986	CRFRC–D Holdings, Inc	DEG Acquisitions, LLC	DEG Acquisitions, LLC.
20070991	Ares Corporate Opportunities Fund, L.P.	EXCO Resources, Inc	EXCO Resources, Inc.
20070995	JLL Partners Fund, V, L.P	Patheon Inc	Patheon Inc.

For Further Information Contact: Sandra M. Peay, Contact Representative or Renee Hallman, Contact Representative. Federal Trade Commission, Premerger Notification Office, Bureau of Competition, Room H–303, Washington, DC 20580, (202) 326–3100.

By Direction of the Commission.

Donald S. Clark,

Secretary.

[FR Doc. 07–1646 Filed 4–3–07; 8:45 am]

BILLING CODE 6750–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the National Coordinator for Health Information Technology; American Health Information Community Population Health and Clinical Care Connections Workgroup Meeting

ACTION: Meeting cancellation.

SUMMARY: This notice announces the cancellation of the 15th meeting of the American Health Information Community Population Health and Clinical Care Connections Workgroup [formerly Biosurvellance Workgroup] in accordance with the Federal Advisory Committee Act (Pub. L. 92–463, 5 U.S.C., App.)

CANCELED DATE/TIME: April 20, 2007, from 10 a.m., to 3:30 p.m. Eastern Daylight Time.

ADDRESSES: Hubert H. Humphrey Building (200 Independence Avenue, SW., Washington, DC 20201), Room 505A. Please bring photo ID for entry to a Federal building).

FOR FURTHER INFORMATION CONTACT: *http://www.hhs.gov/healthit/ahic/population/.*

Dated: March 27, 2007.

Judith Sparrow,

Director, American Health Information Community, Office of Programs and Coordination, Office of the National Coordinator for Health Information Technology.

[FR Doc. 07–1645 Filed 4–3–07; 8:45 am]

BILLING CODE 4150–24–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the Secretary

Findings of Misconduct in Science

AGENCY: Office of the Secretary, HHS.

ACTION: Notice.

SUMMARY: Notice is hereby given that on March 12, 2007 the Department of Health and Human Services (HHS) Debarring Official, on behalf of the Secretary of HHS, issued a final notice of debarment based on the misconduct in science findings of the U.S. Public Health Service (PHS) in the following case:

Rebecca Uzelmeier (formerly known as Rebecca Marcus), Michigan State University: Based on the report of an investigation by Michigan State University (MSU) and additional information obtained by the Office of Research Integrity (ORI) during its oversight review, ORI found that Rebecca Uzelmeier, former doctoral student, Department of Pharmacology and Toxicology, MSU, committed misconduct in science by intentionally and knowingly fabricating and falsifying data in research supported by National Institute of Environmental Health Sciences (NIEHS), National Institutes of Health (NIH), granted R01 ES02520.

ORI issued a charge letter enumerating the above findings of misconduct in science. However, on October 12, 2006, Ms. Uzelmeier filed a request for a hearing under 42 CFR part 93 to dispute these findings before the U.S. Department of Health and Human Services (HHS) Departmental Appeals Board (DAB). On October 19, 2006, ORI moved to dismiss Ms. Uzelmeier's hearing request because it failed to create a genuine dispute of either material fact or law, as required under 42 CFR 93.504. On March 5, 2007, the Administrative Law Judge (ALJ) with the DAB ruled in ORI's favor and dismissed Ms. Uzelmeier's hearing request pursuant to 42 CFR 93.504(a)(2).

The ALJ found that Ms. Uzelmeier's hearing request raised defenses that either were immaterial to the charges of misconduct in science or that the ALJ had no authority to grant Ms. Uzelmeier's request for relief under Part 93.

Specifically, Ms. Uzelmeier knowingly and intentionally;

• Fabricated and falsified data in her research notebook primarily by multiple instances of using data/results generated from one experiment to represent data/results purportedly obtained from one or more entirely different experiments; and

• Fabricated and falsified data in her thesis entitled ''Characterization of the Molecular Mechanism(s) Underlying the Interaction(s) between 2,3,7,8-tetrachlorodibenzo-*p*-Dioxin Mediated and Interferon Gamma Mediated Signal Transduction,'' including falsifying and fabricating autoradiographic films, computer image files scanned from those films, numerical data reduced from those computer files, documentation of those results in her black three-ring binder, and data in associated multiple figures and projection slides.

Ms. Uzlmeier's research concerned the interaction between the environmental toxin, dioxin, and a cytokine, interferon, on cellular signaling in the immune system. The approach was to exploit dioxin, or ''TCDD'' (2,3,7,8-tetrachlorodibenzo-*p*-dioxin), as a probe that suppresses the immune system to delineate a role for the aryl hydrocarbon receptor protein (AhR), which is a cytosolic receptor that can be transported to the nucleus to also act as a nuclear transcription factor. The specific aim was to determine whether the mechanism of action of a naturally occurring regulatory factor, interferon-γ (IFN-γ), to antagonize the immunosuppressive actions of dioxin, was through reduced AhR signaling.

Ms. Uzelmeier's actions caused the withdrawal of a manuscript that had been submitted for publication, the withdrawal of her mentor's PHS grant application, and her dismissal from graduate school.

The following administrative actions have been implemented for a period of five (5) years, beginning on March 12, 2007:

(1) Ms. Uzelmeier has been debarred from any contracting or subcontracting with any agency of the United States Government and from eligibility or involvement in nonprocurement programs of the United States Government referred to as ''covered transactions'' as defined in the debarment regulations at 2 CFR 180 and 376; and

(2) Ms. Uzelmeier is prohibited from serving in any advisory capacity to PHS including but not limited to service on any PHS advisory committee, board, and/or peer review committee, or as consultant.

FOR FURTHER INFORMATION CONTACT: Director, Division of Investigative Oversight, Office of Research Integrity, 1101 Wootton Parkway, Suite 750, Rockville, MD 20852, (240) 453–8800.

Chris B. Pascal,

Director, Office of Research Integrity.

[FR Doc. 07–1616 Filed 4–3–07; 8:45 am]

BILLING CODE 4160–17–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Agency for Healthcare Research and Quality

Solicitation for Nominations for Members of the U.S. Preventive Services Task Force

AGENCY: Agency for Healthcare Research and Quality (AHRQ), HHS.

ACTION: Solicits nominations for new members.

SUMMARY: The Agency for Healthcare Research and Quality (AHRQ) invites nominations of individuals qualified to serve as members of the U.S. Preventive Services Task Force (the Task Force).

The Task Force, a standing, independent panel of private-sector experts in prevention and primary care, is composed of members appointed to serve for four-year terms with an option for reappointment. New members are selected each year to replace (approximately) one fourth of the Task Force members, i.e., those who are completing their appointments. Individuals nominated but not appointed in previous years, as well as those newly nominated, are considered in the annual selection process.

Task Force members meet three times a year for two days in the Washington, DC area. Member duties include reviewing and preparing comments (off site) on systematic evidence reviews prior to discussing and making recommendations on preventive services, drafting final recommendation documents, and participating in workgroups on specific topics or methods. AHRQ particularly encourages nominations of women, members of minority populations, and persons with disabilities. Interested individuals can self nominate. Organizations and individuals may nominate one or more persons qualified for membership on the Task Force.

Qualification Requirements: The mission of the Task Force is to produce evidence-based recommendations on the appropriate screening, counseling, and provision of preventive medication for asymptomatic patients seen in the primary care setting. Therefore, in order to qualify for the Task Force, an applicant or nominee MUST demonstrate the following:

1. Knowledge and experience in the critical evaluation of research published in peer reviewed literature and in the methods of evidence review;

2. Understanding and experience in the application of synthesized evidence to clinical decision-making and/or policy;

3. Expertise in disease prevention and health promotion;

4. Ability to work collaboratively with peers; and,

5. Clinical expertise in the primary health care of children and/or adults, and/or expertise in counseling and behavioral interventions for primary care patients. Some Task Force members without primary health care clinical experience may be selected based on their expertise in methodological issues such as medical decision making, clinical epidemiology, behavioral medicine, and health economics.

Strongest consideration will be given to individuals who are recognized nationally or intentionally for scientific leadership within their field of expertise. Applicants must have no substantial conflicts of interest that would impair the scientific integrity of the work of the Task Force including financial, intellectual, or other conflicts.

DATES: All nominations submitted in writing or electronically, and received by Thursday, May 31, 2007, will be considered for appointment to the Task Force.

Nominated individuals will be selected for the Task Force on the basis of their qualifications (in particular, those that address the required qualifications, outlined above) and the current expertise needs of the Task Force. It is anticipated that 4 individuals will be invited to serve on the Task Force beginning in January, 2008. AHRQ will retain and consider for future vacancies the nominations of those not selected during this cycle.

ADDRESSES: Submit your responses either in writing or electronically to: Gloria Washington, ATTN: USPSTF Nominations, Center for Primary Care, Prevention, and Clinical Partnerships, Agency for Healthcare Research and Quality, 540 Gaither Road, Rockville,

Maryland 20850, *Gloria.Washington@ahrq.hhs.gov*.

Nomination Submissions

Nominations may be submitted in writing or electronically, but must include (1) the applicant's current curriculum vitae and contact information, (2) a letter explaining how this individual meets the qualification requirements and how he/she would contribute to the Task Force. The letter should also attest to the nominee's willingness to serve as a member of the Task Force.

AHRQ will later ask persons under serious consideration for membership to provide detailed information that will permit evaluation of possible significant conflicts of interest. Such information will concern matters such as financial holdings, consultancies, and research grants or contracts.

Nomination Selection

Nominations for the Task Force will be selected on the basis of qualifications as outlined above (see Qualification Requirements) and the current expertise needs of the Task Force.

Arrangement for Public Inspection

Nominations and applications are kept on file at the Center for Primary Care, Prevention and Clinical Partnerships, and are available for review during business hours. AHRQ does not reply to individual responses, but considers all nominations in selecting members. Information regarded as private and personal, such as a nominee's social security number, home and internet addresses, home telephone and fax numbers, or names of family members will not be disclosed to the public. This is in accord with agency confidentiality policies and Department regulations (45 CFR 5.67).

FOR FURTHER INFORMATION CONTACT: Gloria Washington at *Gloria.Washington@ahrq.hhs.gov*.

SUPPLEMENTARY INFORMATION:

Background

Under Title IX of the Public Health Service Act, AHRQ is charged with enhancing the quality, appropriateness, and effectiveness of health care services and access to such services. AHRQ accomplishes these goals through scientific research and promotion of improvements in clinical practice, including prevention of diseases and other health conditions, and improvements in the organization, financing, and delivery of health care services (42 U.S.C. 299–299c–7 as amended by the Healthcare Research and Quality Act of 1999, codified in scattered sections of 42 U.S.C.

The Task Force is an independent expert panel, first established in 1984 under the auspices of the U.S. Public Health Service. Currently, the USPSTF, under AHRQ's authorizing legislation (see in particular, 42 U.S.C. 299b–4(a), is convened at the call of the Director of AHRQ. The Task Force is charged with rigorously evaluating the effectiveness, cost-effectiveness and appropriateness of clinical preventive services and formulating or updating recommendations for primary care clinicians regarding the appropriate provision of preventive services. The USPSTF transitioned to a standing Task Force in 2001. Current Task Force recommendations and associated evidence reviews are available on the Internet (*http://www.preventiveservices.ahrq.gov*).

Dated: March 27, 2007.

Carolyn M. Clancy,

Director.

[FR Doc. 07–1639 Filed 4–3–07; 8:45 am]

BILLING CODE 4160–90–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

[60Day–07–06BD]

Proposed Data Collections Submitted for Public Comment and Recommendations

In compliance with the requirement of Section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995 for opportunity for public comment on proposed data collection projects, the Centers for Disease Control and Prevention (CDC) will publish periodic summaries of proposed projects. To request more information on the proposed projects or to obtain a copy of the data collection plans and instruments, call 404–639–5960 and send comments to Joan Karr, CDC Acting Reports Clearance Officer, 1600 Clifton Road, MS–D74, Atlanta, GA 30333 or send an e-mail to *omb@cdc.gov.*

Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the proposed collection of information; (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 through the use of automated collection techniques or other forms of information technology. Written comments should be received within 60 days of this notice.

Proposed Project

Economic Analysis of the National Breast and Cervical Cancer Early Detection Program—New National Center for Chronic Disease Prevention and Health Promotion (NCCDPHP), Centers for Disease Control and Prevention (CDC).

Background and Brief Description

CDC administers the National Breast and Cervical Cancer Early Detection Program (NBCCEDP) that provides critical breast and cervical cancer screening services to underserved women in the United States, the District of Columbia, 4 U.S. territories, and 13 American Indian/Alaska Native organizations. The program provides breast and cervical cancer screening for eligible women who participate in the program as well as diagnostic procedures for women who have abnormal findings. For the past decade, the NBCCEDP has provided over 5 million breast and cervical cancer screening and diagnostic exams to almost 2.1 million low-income women. Women diagnosed with cancer through the program are eligible for Medicaid coverage through the Breast and Cervical Cancer Prevention and Treatment Act passed by Congress in 2000.

The NBCCEDP is the largest organized cancer screening program in the United States but to date there has been no systematic analysis of the economic costs incurred by the program. CDC is proposing to collect one year (period covering 07/01/2005–06/30/2006) of cost data from all the 68 NBCCEDP grantees to assess the cost and cost-effectiveness of the program. The information required to perform an activity-based cost analysis includes: staff and consultant salaries, screening costs, contracts and material costs, provider payments, in-kind contributions, administrative costs, allocation of funds and staff time devoted to specific program activities. CDC has developed and tested a draft questionnaire with 9 NBCCEDP grantees to assess the ability of the grantees to provide the cost data elements requested, identify the cost information required, and to complete the questionnaire within the allocated timeframe. The grantees were able to

complete the questionnaire with the instructions provided.

The activity-based cost data provided by the 68 grantees will be used to evaluate the programs to ensure the most appropriate use of limited program resources. Performing an assessment of the resources expended on NBCCEDP will provide valuable information to the CDC and it partners for improving program efficiency within the various components of the NBCCEDP including screening, case management, outreach, and overall management. The detailed cost data will allow CDC to assess the costs of the various program components, identify factors that impact average cost, perform cost-effectiveness analysis and develop a resource allocation tool. The collection and analysis of the cost data will allow CDC to utilize a more systematic process to allocate program resources based on grantees' past performance, level of efficiency, and future needs.

Since information on screening and diagnosis volumes (the effectiveness measures) are already collected as part of the Minimum Data Elements (MDEs), the additional burden on grantees to provide the requested cost data will be modest. If future cost data collection efforts are undertaken, the response burden would be further reduced because the infrastructure established to capture the data is already in place.

There are no costs to respondents except their time to participate in the survey.

ESTIMATED ANNUALIZED BURDEN HOURS

Type of respondent	Form name	Number of respondents	Number responses per respondent	Average burden per response (in hours)	Total burden hours
Program Director	Cost Assessment Tool	68	1	4	272
Business Manager		68	1	4	272
Data Manager		68	1	14	952
Total					1,496

Dated: March 28, 2007.

Joan F. Karr,

Acting Reports Clearance Officer, Centers for Disease Control and Prevention.

[FR Doc. E7–6275 Filed 4–3–07; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

[60Day–07–06AY]

Proposed Data Collections Submitted for Public Comment and Recommendations

In compliance with the requirement of Section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995 for opportunity for public comment on proposed data collection projects, the Centers for Disease Control and Prevention (CDC) will publish periodic summaries of proposed projects. To request more information on the proposed projects or to obtain a copy of the data collection plans and instruments, call 404–639–5960 and send comments to Joan Karr, CDC Acting Reports Clearance Officer, 1600 Clifton Road, MS–D74, Atlanta, GA 30333 or send an e-mail to *omb@cdc.gov.*

Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the proposed collection of information; (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 through the use of automated collection techniques or other forms of information technology. Written comments should be received within 60 days of this notice.

Proposed Project

Evaluation of the Spanish-Language Campaign ''Good Morning Arthritis, Today you will not defeat us.''—New—National Center for Chronic Disease Prevention and Health Promotion (NCCDPHP), Centers for Disease Control and Prevention (CDC).

Background and Brief Description

Arthritis affects nearly 43 million Americans, or about one in every six people, and is the leading cause of disability among adults in the United States. Because of the broad public health impact of this disease, the Centers for Disease Control and Prevention (CDC) developed the National Arthritis Action Plan in 1998 as a comprehensive approach to reducing the burden of arthritis in the United States.

As part of its efforts to implement the National Arthritis Action Plan, CDC developed and tested a health communications campaign promoting physical activity among Caucasian and African-American adults with arthritis. In 2003–2004, CDC developed a similar campaign for Spanish-speaking people with arthritis. Hispanic populations have a slightly lower prevalence rate of self-reported, doctor-diagnosed arthritis, but Hispanics with arthritis report greater work limitations, and higher rates of severe pain than do Caucasian populations with arthritis.

The Spanish-language campaign, Good Morning Arthritis, Today you will not defeat us, is designed to reach Spanish speaking adults with arthritis who are aged 45–64, who have high school education or less, and whose annual income is less than $35,000. The key message elements of the Spanish language health communications campaign are similar to its English counterpart, as are the campaign objectives and materials. The campaign objectives are to increase target audience members' (1) Beliefs about physical activity as an arthritis management strategy (there are ''things they can do'' to make arthritis better, and physical activity is an important part of arthritis management); (2) Knowledge of the benefits of physical activity and appropriate physical activity for people with arthritis; (3) Confidence in their ability to be physically active, and (4) Trial of physical activity behaviors. Based on formative research, campaign materials refer to exercise instead of physical activity. Campaign materials include; print ads, 30- and 60-second radio ads and public service announcements, and desktop displays with brochures for

pharmacies, doctors' offices, and community centers.

In the Fall of 2005, the Spanish language campaign was pilot tested by 5 state health departments that receive funding from CDC for their arthritis programs. CDC will eventually disseminate these materials to all 36 CDC-funded states. The 5 preliminary pilot tests focused on reach and exposure; a more thorough evaluation is necessary to assess impact of the campaign. This information will be used to guide the public health practice of the 36 state arthritis programs and their partners.

CDC will conduct an evaluation of the impact of the Spanish language health communications campaign on the exercise/physical activity-related attitudes, beliefs, and behaviors among the target audience of Spanish-speaking people with arthritis. There are no costs to the respondents other than their time.

ESTIMATED ANNUALIZED BURDEN HOURS

Respondents	Number of respondents	Number of responses per respondent	Average burden per response (in hours)	Total burden (in hours)
Screening Survey	12,000	1	2/60	400
Telephone Survey	2,500	1	15/60	625
Total				1,025

Dated: March 28, 2007.

Joan F. Karr,

Acting Reports Clearance Officer, Centers for Disease Control and Prevention.

[FR Doc. E7–6276 Filed 4–3–07; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Disease, Disability, and Injury Prevention and Control Special Emphasis Panel (SEP): Technical Support for Birth Defects and Developmental Disabilities Prevention Education Efforts, Contract Solicitation Number (CSN) 2006–N–08835

In accordance with Section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463), the Centers for Disease Control and Prevention (CDC) announces the following meeting of the aforementioned SEP:

Time and Date: 12 p.m.–3 p.m., April 30, 2007 (Closed).

Place: Teleconference, Centers for Disease Control and Prevention, 1600 Clifton Road, NE., Atlanta, GA 30333.

Status: The meeting will be closed to the public in accordance with provisions set forth in Section 552b(c)(4) and (6), Title 5 U.S.C., and the Determination of the Director, Management Analysis and Services Office, CDC, pursuant to Public Law 92–463.

Matters to be Discussed: The meeting will include the review, discussion, and evaluation of applications received in response to CSN 2006–N–08835, ''Technical Support for Birth Defects and Developmental Disabilities Prevention Education Efforts.''

For Further Information Contact: Christine Morrison, Ph.D., Scientific Review Administrator, Centers for Disease Control and Prevention, 1600 Clifton Road NE., Mailstop D72, Atlanta, GA 30333, Telephone 404.639.3098.

The Director, Management Analysis and Services Office, has been delegated the authority to sign **Federal Register** notices pertaining to announcements of meetings and other committee management activities, for both CDC and the Agency for Toxic Substances and Disease Registry.

Dated: March 28, 2007.

Elaine L. Baker,

Acting Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. E7–6270 Filed 4–3–07; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

Preparation for International Conference on Harmonisation Meetings in Brussels, Belgium; Public Meeting

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice of meeting.

SUMMARY: The Food and Drug Administration (FDA) is announcing a public meeting entitled ''Preparation for ICH Meetings in Brussels, Belgium'' to provide information and receive comments on the International Conference on Harmonisation (ICH) as well as the upcoming meetings in Brussels, Belgium. The topics to be discussed are the topics for discussion at the forthcoming ICH steering committee meeting. The purpose of the meeting is to solicit public input prior to the next steering committee and expert working groups meetings in Brussels, Belgium May 5–10, 2007, at which discussion of the topics underway and the future of ICH will continue.

Date and Time: The meeting will be held on Friday April 6, 2007, from 3:30 p.m. to 5 p.m.

Location: The meeting will be held at 5600 Fishers Lane, third floor, Conference Room G, Rockville, MD 20857. For security reasons, all attendees are asked to arrive no later than 3:20 p.m., as you will be escorted from the front entrance of 5600 Fishers Lane to Conference Room G.

Contact Person: Michelle Limoli, Office of the Commissioner (HFG–1), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857, 301–827–0908, e-mail: *michelle.limoli@fda.hhs.gov*, FAX: 301–827–0003.

Registration and Requests for Oral Presentations: Send registration information (including name, title, firm name, address, telephone, and fax number), written material, and requests to make oral presentations, to the contact person by April 5, 2007.

If you need special accommodations due to a disability, please contact Michelle Limoli as soon as possible.

SUPPLEMENTARY INFORMATION: The ICH was established in 1990 as a joint regulatory/industry project to improve, through harmonization, the efficiency of the process for developing and registering new medicinal products in Europe, Japan, and the United States without compromising the regulatory obligations of safety and effectiveness.

In recent years, many important initiatives have been undertaken by regulatory authorities and industry

associations to promote international harmonization of regulatory requirements. FDA has participated in many meetings designed to enhance harmonization and is committed to seeking scientifically-based harmonized technical procedures for pharmaceutical development. One of the goals of harmonization is to identify and then reduce differences in technical requirements for medical product development among regulatory agencies. ICH was organized to provide an opportunity for harmonization initiatives to be developed with input from both regulatory and industry representatives. ICH is concerned with harmonization among three regions: The European Union, Japan, and the United States. The six ICH sponsors are the European Commission; the European Federation of Pharmaceutical Industries Associations; the Japanese Ministry of Health, Labor and Welfare; the Japanese Pharmaceutical Manufacturers Association; the Centers for Drug Evaluation and Research and Biologics Evaluation and Research, FDA; and the Pharmaceutical Research and Manufacturers of America. The ICH Secretariat, which coordinates the preparation of documentation, is provided by the International Federation of Pharmaceutical Manufacturers Associations. The ICH steering committee includes representatives from each of the ICH sponsors and Health Canada, the European Free Trade Area, and the World Health Organization. The ICH process has achieved significant harmonization of the technical requirements for the approval of pharmaceuticals for human use in the three ICH regions.

The current ICH process and structure can be found at the following Web site: *http://www.ich.org*.

Interested persons may present data, information, or views orally or in writing, on issues pending at the public meeting. Oral presentations from the public will be scheduled between approximately 4:30 p.m. and 5 p.m. Time allotted for oral presentations may be limited to 10 minutes. Those desiring to make oral presentations should notify the contact person by April 5, 2007, and submit a brief statement of the general nature of the evidence or arguments they which to present, the names and addresses, phone number, fax, and e-mail of proposed participants, and an indication of the approximate time requested to make their presentation.

The agenda for the public meeting will be made available via the Internet at *http://www.fda.gov/cder/meeting/ICH_20060508.htm*.

Transcripts: Transcripts of the meeting may be requested in writing from the Freedom of Information Office (HFI–35), Food and Drug Administration, 5600 Fishers Lane, rm. 6–30, Rockville, MD 20857, approximately 15 working days after the meeting at a cost of 10 cents per page.

Dated: March 28, 2007.

Jeffrey Shuren,

Assistant Commissioner for Policy.

[FR Doc. 07–1633 Filed 3–29–07; 3:56 pm]

BILLING CODE 4160–01–S

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Indian Health Service

List of Recipients of Indian Health Scholarships Under the Indian Health Scholarship Program

The regulations governing Indian Health Care Improvement Act Programs (Pub. L. 94–437) provide at 42 CFR 136.334 that the Indian Health Service shall publish annually in the **Federal Register** a list of recipients of Indian Health Scholarships, including the name of each recipient, school and Tribal affiliation, if applicable. These scholarships were awarded under the authority of Sections 103 and 104 of the Indian Health Care Improvement Act, 25 U.S.C. 1613–1613a, as amended by the Indian Health Care Amendments of 1988, Pub. L. 100–713.

The following is a list of Indian Health Scholarship Recipients funded under Sections 103 and 104 for Fiscal Year 2006:

Adams, Staci Brook, Northern Oklahoma College, Ponca Tribe of Indians of Oklahoma.

Ahenakew, Carol Marie, Walla Walla College, Blackfeet Tribe of the Blackfeet Indian Reservation of Montana.

Albers, Travis Alan, University of Mary, Turtle Mountain Band of Chippewa Indians of North Dakota.

Allen, Bryan Zachary, Southwestern Oklahoma State University, Choctaw Nation of Oklahoma.

Arredondo, Michael Howard, University of Minnesota/Duluth, Eastern Shawnee Tribe of Oklahoma.

Augare-Deal, Rael, University of Kansas, Blackfeet Tribe of the Blackfeet Indian Reservation of Montana.

Azure, Donna Rae, Turtle Mountain Community College, Turtle Mountain Band of Chippewa Indians of North Dakota.

Azure, Krysten Ross, University of North Dakota, Sisseton-Wahpeton Sioux Tribe of the Lake Traverse Reservation, South Dakota.

Babbitt, Jaime Lynn, Indiana University, Navajo Nation, Arizona, New Mexico& Utah.

Baker, Allison Marie, University of North Dakota, Three Affiliated Tribes of the Fort Berthold Reservation, North Dakota.

Baker, Laiel Inez, University of North Dakota, Three Affiliated Tribes of the Fort Berthold Reservation, North Dakota.

Baker, Valerie, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.

Bales-Poirot, Deidre Leann, University of Missouri/Columbia, Eastern Shawnee Tribe of Oklahoma.

Banteah, Melinda Erika, University of New Mexico/Albuquerque, Zuni Tribe of the Zuni Reservation, New Mexico.

Barnett, Stephanie Deann, University of Pittsburgh, Cherokee Nation, Oklahoma.

Barrett, Courtney Paige, University of Oklahoma, Seminole Nation of Oklahoma.

Bayer, Amelia Dianne, University of New Mexico, Choctaw Nation of Oklahoma.

Beals, Bryan James, University of North Dakota, Muscogee (Creek) Nation, Oklahoma.

Beardslee, Amber Rochelle, The University of Puget Sound, Central Council of Tlingit & Haida Indian Tribes.

Beaver, Aaron Don, University of Oklahoma, Choctaw Nation of Oklahoma.

Beaver, Allen Don, University of Oklahoma, Choctaw Nation of Oklahoma.

Bebeau, Shari Kaye, University of Minnesota, Minnesota Chippewa Tribe, Minnesota.

Becenti, Elton, New Mexico State University, Navajo Nation, Arizona, New Mexico & Utah.

Becker, Tischa Lee, University of New Mexico, Cherokee Nation, Oklahoma.

Begay, Melanie, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.

Begay, Monica Calley, University of New Mexico/Albuquerque, Navajo Nation, Arizona, New Mexico & Utah.

Begay, Velda Ann, Arizona State University, Navajo Nation, Arizona, New Mexico & Utah.

Begaye, Adrienne Marie, University of Arizona, Navajo Nation, Arizona, New Mexico & Utah.

Begaye, Amelia June, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.

Begaye, Julianna, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.

Bekis, Olin Jimmie, University of New Mexico/Albuquerque, Navajo Nation, Arizona, New Mexico & Utah.
Belgarde, Robin Ramona, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Bell, Lauren Beth, University of Oklahoma, Cherokee Nation, Oklahoma.
Benallie, Mariah J., University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Benally, Gerald Dean, San Juan Community College, Navajo Nation, Arizona, New Mexico & Utah.
Benally, Joann J., Northern Arizona University, Navajo Nation, Arizona, New Mexico & Utah.
Benally, Jolene, Northern Arizona University, Navajo Nation, Arizona, New Mexico & Utah.
Bercier, Audrey Lee, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Bernard, Kenneth Richard Lee, Harvard University, Turtle Mountain Band of Chippewa Indians of North Dakota.
Big Hair, Andrea Rochelle, Montana State University/Billings, Crow Tribe of Montana.
Bighorn, Mary Johanna, University of Montana, Assiniboine & Sioux Tribes of the Fort Peck Indian Reservation, Montana.
Billy, Larissia Jenny, University of Alaska, Blackfeet Tribe of the Blackfeet Indian Reservation of Montana.
Bissonette, Melvina Deneal, University of New Mexico, Oglala Sioux Tribe of the Pine Ridge Reservation, South Dakota.
Blackfox, Sasha Denee, Northeastern State University, Cherokee Nation, Oklahoma.
Blankenship, Lacey Kay, Southwestern Oklahoma State University, Cherokee Nation, Oklahoma.
Blevins, Regina Kay, North Dakota State University, Choctaw Nation of Oklahoma.
Boardman, RD Carter, Brigham Young University, Choctaw Nation of Oklahoma.
Boatwright, Melinda Lea, University of Oklahoma, Choctaw Nation of Oklahoma.
Bost, Dekoda Kole, University of Central Oklahoma, Choctaw Nation of Oklahoma.
Bousquet, Andrea Nicole, Northeastern State University, Cherokee Nation, Oklahoma.
Bowekaty, Althea, University of Phoenix, Zuni Tribe of the Zuni Reservation, New Mexico.
Bowers, Sherri Lynn, Rose State College, Choctaw Nation of Oklahoma.
Bradfield, Lavone Glema, Emory University, Standing Rock Sioux Tribe of North & South Dakota.
Brady, Meagan Leigh, University of Oklahoma, Comanche Nation, Oklahoma.
Bressman, Rebecca Rae, Portland State University, Citizen Potawatomi Nation, Oklahoma.
Brewster, Sarah Kate, University of Tulsa, Muscogee (Creek) Nation, Oklahoma.
Brockelman, Cassandra May, Southwestern Oklahoma State University, Seminole Nation of Oklahoma.
Brooks, Seth Russell, University of Oklahoma, Choctaw Nation of Oklahoma.
Brooksher, Callen Brett, Southwestern Oklahoma State University, Chickasaw Nation, Oklahoma.
Brown, Candice Lynn, Salish Kootenai College, Confederated Salish & Kootenai of the Flathead Reservation, Montana.
Brown, Cerissa Kalani, Oklahoma State University, Cherokee Nation, Oklahoma.
Brown, Christina Ann, University of North Dakota, Paiute-Shoshone Indians of the Bishop Community of the Bishop Colony, California.
Brown, Christy Lynn, University of Oklahoma, Cherokee Nation, Oklahoma.
Brown, Gerald Lee, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Brown, Randy Neil, Southwestern Indian Polytechnic Institute, Pueblo of Laguna, New Mexico.
Buckner, Jennifer Lynn, Arizona State University, Cheyenne-Arapaho Tribes of Oklahoma.
Buettner, Brian Edwin, University of Oklahoma, Citizen Potawatomi Nation, Oklahoma.
Burden, Katie Nicole, East Central University, Muscogee (Creek) Nation, Oklahoma.
Byrd, Alpheus Lee, Carl Albert State College, Cherokee Nation, Oklahoma.
Cain, Melanie Joy, Oklahoma State University, Pueblo of Santa Clara, New Mexico.
Cardenas, Dharshini, Dixie State College of Utah, Navajo Nation, Arizona, New Mexico & Utah.
Carey, Amanda Kay, A.T. Still University, Cherokee Nation, Oklahoma.
Carey, Candice Joy, Northeastern State University, Cherokee Nation, Oklahoma.
Casillas, Denise Myra, University of South Dakota, Cheyenne River Sioux Tribe of the Cheyenne River Reservation, South Dakota.
Castillo, Desiree Nicole, Baylor University, Choctaw Nation of Oklahoma.
Cavanaugh, Casey Lynne, Ohio State University, Shoshone-Paiute Tribes of the Duck Valley Reservation, Nevada.
Cavanaugh, Erica Rose, University of North Dakota, Spirit Lake Tribe, North Dakota.
Chancellor, Sarah Ellen, Carl Albert State College, Choctaw Nation of Oklahoma.
Chapman, Ashley Elizabeth, Nova Southeastern University, Mohegan Indian Tribe of Connecticut.
Charley, Cherilynn Lea, San Juan Community College, Navajo Nation, Arizona, New Mexico & Utah.
Clark, Jacqueline Renee, East Central University, Chickasaw Nation, Oklahoma.
Clarkson-Ray, Rachel Beth, Oklahoma State University, Cherokee Nation, Oklahoma.
Clauschee, Susan Francine, University of Arizona, Navajo Nation, Arizona, New Mexico & Utah.
Clemons, Danielle Nicole, Northern Arizona University, Pueblo of Acoma, New Mexico.
Cody, Leigh, Northern Arizona University, Navajo Nation, Arizona, New Mexico & Utah .
Cody, Teshina T., University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Colelay, Aletta Lynn, Northland Pioneer College, White Mountain Apache.
Coleman-Hack, Kristi Lynn, East Central University, Choctaw Nation of Oklahoma.
Collins, John Tate, University of Oklahoma, Cherokee Nation, Oklahoma.
Comb, Savanah, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Combrink, Mark Alan, Southwestern Oklahoma State University, Chippewa Cree Indians of the Rocky Boy's Reservation, Montana.
Condon, Travis Wayne, North Dakota State University, Standing Rock Sioux Tribe of North & South Dakota.
Conley, Amanda Penner, University of Oklahoma, Chickasaw Nation, Oklahoma.
Constantine, Angie Casina, University of New Mexico/Albuquerque, Native Village of Tyonek.
Cook, Elizabeth Jane, East Central University, Choctaw Nation of Oklahoma.
Cook, Lyle C., University of California, Davis, Cheyenne River Sioux Tribe of the Cheyenne River Reservation, South Dakota.
Coolidge, Deborah Lena, University of Washington, Native Village of Aleknagik.

Coon, Teresa Lynne, University of Oklahoma, Seminole Nation of Oklahoma.
Corbin, Christopher Neal, University of Oklahoma, Cherokee Nation, Oklahoma.
Corcoran, Lauren Rae, University of Montana, Chippewa Cree Indians of the Rocky Boy's Reservation, Montana.
Crain, Stacy Rae, North Dakota State University, Turtle Mountain Band of Chippewa Indians of North Dakota.
Crawley, Misti Kay, Oklahoma State University, Choctaw Nation of Oklahoma.
Cribbs, Carolyn Suze, Sonoma State University, Cherokee Nation, Oklahoma.
Damon, Dezbaa Altaalkii, Arizona School of Dentistry, Navajo Nation, Arizona, New Mexico & Utah.
Damon, Mallary Jenna, University of New Mexico/Gallup, Navajo Nation, Arizona, New Mexico & Utah.
Davis, Abby Sue, University of Alaska, Turtle Mountain Band of Chippewa Indians of North Dakota.
Davis, Brandy Darlene, University of Cincinnati, Eastern Band of Cherokee Indians of North Carolina.
Davis, Krissie Lee, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Davis, Kylie Louise, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Davis, Robert Samuel, University of Washington/Northwest, Bad River Band of the Lake Superior Tribe of Chippewa Indians of the Bad River Reservation, Wisconsin.
Davis-Counts, Heather Rae, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Day, Autumn Ann, Kirksville College, Leech Lake Band.
Dejolie, Crista Lee, Northern Arizona University, Navajo Nation, Arizona, New Mexico & Utah.
Delgado, Jamael Theresa, University of North Dakota, Navajo Nation, Arizona, New Mexico & Utah.
Dempsey, Tanya Corina, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Denetdale, Verdaleen, Drexel University, Navajo Nation, Arizona, New Mexico & Utah.
Dixon, Heather Renee, Black Hills State University, Oglala Sioux Tribe of the Pine Ridge Reservation, South Dakota.
Dodson, Charlene, Dona Ana Branch Community College, Navajo Nation, Arizona, New Mexico & Utah.
Duncan, Caleb Jerome, Northeastern State University, Cherokee Nation, Oklahoma.
Eldridge, Marinda, University of New Mexico/Gallup, Navajo Nation, Arizona, New Mexico & Utah.
Elmore, Amber Dawn, Meridian Technology Center, Chickasaw Nation, Oklahoma.
England (Demientieff), Manon Kristine, University of Alaska/Anchorage, Nenana Native Association.
English, Brittany Renee, Northeastern State University, Cherokee Nation, Oklahoma.
Estes, Abigail Reese, University of Kansas, Cherokee Nation, Oklahoma.
Evans, Amanda Lorna, Montana State University, Confederated Salish & Kootenai of the Flathead Reservation, Montana.
Falcon, Gilbert Raymond, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Falconer, Heidi Cambrie, Southwestern Oklahoma State University, Choctaw Nation of Oklahoma.
Fall, Tara 0., East Central University, Chickasaw Nation, Oklahoma.
Fischer, Monika Caroline, University of Arkansas/Fort Smith, Cherokee Nation, Oklahoma.
Fisher, Jayson Mikel, University of New Mexico, Choctaw Nation of Oklahoma.
Fogle, Robyn Lynn, Bacone College, Muscogee (Creek) Nation, Oklahoma.
Foote, Brittnee Irene, University of Mary, Turtle Mountain Band of Chippewa Indians of North Dakota.
Ford-Bremerman, Jessica Louise, University of Washington, Confederated Tribes and Bands of the Yakama Nation, Washington.
Fourkiller, William Travis, Connors State College, Cherokee Nation, Oklahoma.
Fox, Juanita Mendoza, Strayer University, Sisseton-Wahpeton Sioux Tribe of the Lake Traverse Reservation, South Dakota.
Freeling, Katherine Jane, Oklahoma State University, Cherokee Nation, Oklahoma.
French, Zachary Ashton, University of Oklahoma, Cherokee Nation, Oklahoma.
Gallagher, Shawna Fay, Portland State University, Klammath Tribes, Oregon.
Gibe, Nicole Rachelle, University of Oklahoma, Cherokee Nation, Oklahoma.
Gillies, Kenneth Jay, North Dakota State University, Three Affiliated Tribes of the Fort Berthold Reservation, North Dakota.
Gloshay, Janet Johnson, Gateway Community College, Navajo Nation, Arizona, New Mexico & Utah.
Good, Jennifer Lynn, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Good, Tanya Michelle, Nebraska Methodist College, Red Lake Band of Chippewa Indians, Minnesota.
Goodblanket, Minnie Peshlakai, University of Alaska, Cheyenne-Arapaho Tribes of Oklahoma.
Gore, Nicole Charmaine, Arizona School of Dentistry, Crow Tribe of Montana.
Gorham, Janet Lee, University of Missouri at Kansas City, Seneca-Cayuga Tribe of Oklahoma.
Gorman, Emmeline Paula, Northern Arizona University, Navajo Nation, Arizona, New Mexico & Utah.
Gorman, Jack Gerald, University of California, Davis, Karuk Tribe of California.
Graham, Gerritt Wren, University of Oklahoma, Chickasaw Nation, Oklahoma.
Granbois, Rae Alison, Dakota State University, Turtle Mountain Band of Chippewa Indians of North Dakota.
Gray, Dustin Wayne, Oklahoma Baptist University, Cherokee Nation, Oklahoma.
Grogan, Gary Lee, Boise State University, Aleut.
Groten, Clarence Aaron, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Hajicek, Jodi Lynn, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Hall, Sherry Michelle, North Dakota State College, Three Affiliated Tribes of the Fort Berthold Reservation, North Dakota.
Hardy, Miranda, University of New Mexico/Albuquerque, Navajo Nation, Arizona, New Mexico & Utah.
Hargis, Nicole Leigh, East Central University, Choctaw Nation of Oklahoma.
Harker, Erica Michelle, University of New Mexico, Zuni Tribe of the Zuni Reservation, New Mexico.
Harlan, Erica Sue, Oklahoma State University, Muscogee (Creek) Nation, Oklahoma.
Harp, Emma Beth, Oklahoma State University, Cherokee Nation, Oklahoma.
Harris, Leslie Jo, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Harrison, Gilbert, University of Arizona, Navajo Nation, Arizona, New Mexico & Utah.
Harvey, Melissa R., University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Hawk, Sonny Skye, Northeastern State University, Standing Rock Sioux Tribe of North & South Dakota.
Hayes-Coons, Jennifer Lynn, Har-Ber School of Nursing, Cherokee Nation, Oklahoma.
Hays, Jessica Eileen, Bacone College, Cherokee Nation, Oklahoma.

Hendrex, Douglas Brian, University of North Dakota, Cherokee Nation, Oklahoma.
Henry, David Edmond, Oral Roberts University, Cherokee Nation, Oklahoma.
Henry, Joni Rae, Minot State University, Turtle Mountain Band of Chippewa Indians of North Dakota.
Hight, Teresa Lynn, American Institute of Medical Technology, Pueblo of Laguna, New Mexico.
Hobbs, Patricia Louise, Portland State University, Karuk Tribe of California.
Howell, Jean Gregory, University of Minnesota/Duluth, Cherokee Nation, Oklahoma.
Howell, Jesse Ray, University of Oklahoma, Choctaw Nation of Oklahoma.
Huerth, Benjamin Walter, University of Vermont College, Winnebago of Nebraska.
Hulsey, Heidi Lynne, Pacific University, Lummi Tribe of the Lummi Reservation, Washington.
Huskon, Philbert, Arizona State University, Navajo Nation, Arizona, New Mexico & Utah.
James, Jessica Helena, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Jay, Donna Marie, University of Science & Arts of Oklahoma, Apache Tribe of Oklahoma.
Jensen, Janelle Blake, University of Arizona, Navajo Nation, Arizona, New Mexico & Utah.
Jim, Cheyenne Crystal, University of New Mexico/Albuquerque, Navajo Nation, Arizona, New Mexico & Utah.
Jim, Lawanda T., University of New Mexico/Albuquerque, Navajo Nation, Arizona, New Mexico & Utah.
Jimerson, Billye Rene, Bacone College, Muscogee (Creek) Nation, Oklahoma.
Joe, Felma Marie, New Mexico Highlands University, Navajo Nation, Arizona, New Mexico & Utah.
John, Frederick Jeremy, University of Nevada/Las Vegas, Pyramid Lake Paiute Tribe of the Pyramid Lake Reservation, Nevada.
Johnson, Jamie Leanne, New Mexico State University, Cherokee Nation, Oklahoma.
Johnston, Cara Leanne, Oklahoma State University, Cherokee Nation, Oklahoma.
Jones, Joshua David, Lamar University, Cherokee Nation, Oklahoma.
Jones, Mary Etta, Rogers State College, Cherokee Nation, Oklahoma.
Jones, Myles Randall, University of Nebraska/Omaha, Choctaw Nation of Oklahoma.
Kaiser, Joshua Lee, Rogers State College, Cherokee Nation, Oklahoma.
Kaiser, Megan Lynn, North Dakota State University, White Earth Band.
Keawphalouk, Michelle Dow, University of North Dakota, Muscogee (Creek) Nation, Oklahoma.
Keel, Andrea Lynn, University of Oklahoma, Chickasaw Nation, Oklahoma.
Keplin, Jessi Lee, Minot State University, Turtle Mountain Band of Chippewa Indians of North Dakota.
Kirk, Brant Evan, Oregon Institute of Technology, Klamath Tribes, Oregon.
Kirk, Roxanne Nina Heather, Northern Arizona University, Navajo Nation, Arizona, New Mexico & Utah.
Klade, Adrianne Theresa, Albuquerque Technical Vocation, Navajo Nation, Arizona, New Mexico & Utah.
Knight, Laura Ulogilv, University of Oklahoma, Choctaw Nation of Oklahoma.
Knudson, Nicolette Jean, University of Washington, Sisseton-Wahpeton Sioux Tribe of the Lake Traverse Reservation, South Dakota.
Kuka, Sarah Elizabeth, University of Montana, Blackfeet Tribe of the Blackfeet Indian Reservation of Montana.
Lafromboise, Sandy Marie, Minot State College, Turtle Mountain Band of Chippewa Indians of North Dakota.
Landers, Joseph Henry, University of Oklahoma, Muscogee (Creek) Nation, Oklahoma.
Langager, Jason Michael, Brigham Young University, Turtle Mountain Band of Chippewa Indians of North Dakota.
Langan, Ashley Winona, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Largo, Revina, University of Utah, Navajo Nation, Arizona, New Mexico & Utah.
Larney, Kristi Tafv, Southwestern Oklahoma State University, Seminole Nation of Oklahoma.
Larocque, Angie Lynn, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Larsen, Chrissy Marie, Southwest Missouri State University, Seneca-Cayuga Tribe of Oklahoma.
Lauderdale, Lisa Ann, University of Oklahoma, Kickapoo Tribe of Oklahoma.
Lawrence, Jordan Shay, Presentation College, Cheyenne River Sioux Tribe of the Cheyenne River Reservation, South Dakota.
Leslie (Lay), Pamela Christine, William Howard Taft University, Muscogee (Creek) Nation, Oklahoma.
Lewis, Sheyenne Leigh, University of New Mexico/Albuquerque, Navajo Nation, Arizona, New Mexico & Utah.
Lonasee, Samantha, University of New Mexico, Zuni Tribe of the Zuni Reservation, New Mexico.
Long, Chrissy Jaclyn, High-Tech Institute, Navajo Nation, Arizona, New Mexico & Utah.
Longhurst, Claire Frances, University of North Dakota, Navajo Nation, Arizona, New Mexico & Utah.
Lorenzo, Tara Ann, University of Kansas, Navajo Nation, Arizona, New Mexico & Utah.
Losik-Welch, Roberta Toneena, Everett Community College, Tulalip Tribes of the Tulalip Reservation, Washington.
Lovato, Kristin Ann, Arizona State University, Pueblo of Santo Domingo, New Mexico.
Lowry, Jodie Roberta, Winthrop University, Lumbee, North Carolina.
Luedecke, James Anthony, University of Arkansas, Cherokee Nation, Oklahoma.
Lyons, Keri Diane, Bacone College, Cherokee Nation, Oklahoma.
Maddox, Kevin Wayne, Lecom Bradenton, Muscogee (Creek) Nation, Oklahoma.
Maloney, Violet Spring, Northern Arizona University, Navajo Nation, Arizona, New Mexico & Utah.
Manheimer, Sophina Lynn, University of Rochester, Navajo Nation, Arizona, New Mexico & Utah.
Mannila, Anthony Lee, College of St. Scholastica, Bad River Band of the Lake Superior Tribe of Chippewa Indians of the Bad River Reservation, Wisconsin.
Manning, Tessa Leigh, University of Texas Southwestern Medical School, Chickasaw Nation, Oklahoma.
Martin-Tiller, Linda Christine, University of California/San Francisco, Confederated Tribes of the Siletz Reservation, Oregon.
Martinez, Jolynn, University of New Mexico/Albuquerque, Navajo Nation, Arizona, New Mexico & Utah.
Martinez, Shawna Lynn, University of Alaska/Anchorage, Navajo Nation, Arizona, New Mexico & Utah.
Matlock, Jazmin, Oklahoma State University, Cherokee Nation, Oklahoma.
Matthews, William Burt Lewis, Oklahoma State University, Cherokee Nation, Oklahoma.
Mayes, Nicole Rachel, Oklahoma State University, Cherokee Nation, Oklahoma.
McCloud, Kelly Sue, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
McDaniels, Christopher Michael, Northeastern State University, Cherokee Nation, Oklahoma.
Mcgeshick, Cole David, University of Washington, Sokaogon Chippewa Community, Wisconsin.
McGinn, Michelle Lee, New Mexico Highlands University, Pueblo of Acoma, New Mexico.

McGraw, Crystal Annette, University of Minnesota, Duluth, Sisseton-Wahpeton Sioux Tribe of the Lake Traverse Reservation, South Dakota.
McLemore, Alison Denise, Southwestern Oklahoma State University, Cherokee Nation, Oklahoma.
McLemore, Dustin James, University of Oklahoma, Caddo Indian Tribe of Oklahoma.
McPherson, Patricia Lee Ann, University of Washington, Quapaw Tribe of Indians, Oklahoma.
Meierotto, Chelsie Leigh Chelsea, University of Minnesota, Red Cliff Band of Lake Superior of Chippewa Indians of Wisconsin.
Mika, Krista Leigh, University of Minnesota, Bad River Band of the Lake Superior Tribe of Chippewa Indians of the Bad River Reservation, Wisconsin.
Miller, Carl Eugene, Rosalind Franklin University, Muscogee (Creek) Nation, Oklahoma.
Miller, Jacklyn Jean, University of North Dakota, Oglala Sioux Tribe of the Pine Ridge Reservation, South Dakota.
Miller, John Ross, Oklahoma State University, Cherokee Nation, Oklahoma.
Mills, Victoria Lanayne, Northeastern State University, Muscogee (Creek) Nation, Oklahoma.
Moalemi, Nooshin Megan, Touro University/Nevada, Navajo Nation, Arizona, New Mexico & Utah.
Mogelnicki, Lisa Suzanne, Des Moines University, Cherokee Nation, Oklahoma.
Morales, Ruby Ann, Northern Arizona University, Navajo Nation, Arizona, New Mexico & Utah.
Morin, Georgia Maria, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Morris, Gerald Wayne, Indiana University, Pokagon Band of Potawatomi Indians, Michigan and Indiana.
Morris, Winifred, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Morrison, Clint Justin, University of Oklahoma, Choctaw Nation of Oklahoma.
Morton, Sha-Rhonda Michelle, Oklahoma State University, Cherokee Nation, Oklahoma.
Murphy, Sharolyn Fannie, Rose State College, Chickasaw Nation, Oklahoma.
Murray, Carl Arthur, University of Oklahoma, Choctaw Nation of Oklahoma.
Murray, Sara Emily, University of Oklahoma, Choctaw Nation of Oklahoma.
Nail, Cynthia Diane, East Central University, Chickasaw Nation, Oklahoma.
Nelson, Celeste Irene, Dartmouth, Ely Shoshone Tribe of Nevada.
Nelson, Deann Lynn, University of New Mexico/Gallup, Navajo Nation, Arizona, New Mexico & Utah.
Nez, Yolanda Primrose, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Nicholson, Kasey Joseph, Montana State University/Billings, Fort Belknap Indian Community of the Fort Belknap Reservation of Montana.
Nicholson, Reuben Samuel, University of Alaska, Nome Eskimo Community.
Nix, Micah Douglass, Oklahoma State University, Cherokee Nation, Oklahoma.
Noisy Hawk, Lyle James, University of Minnesota, Oglala Sioux Tribe of the Pine Ridge Reservation, South Dakota.
Norris, Valerie, University of Minnesota, Red Lake Band of Chippewa Indians, Minnesota.
Not Afraid, Rosebud Faith, Montana State University/Bozeman, Crow Tribe of Montana.
O'Neal, Brandy Michelle, Oklahoma State University, Cherokee Nation, Oklahoma.
O'Brien, Nancy Sue, Rio Salado College, Cherokee Nation, Oklahoma.
O'Connell, Meghan Curry, University of Washington, Cherokee Nation, Oklahoma.
Old Coyote, Edwina Mae, University of North Dakota, Crow Tribe of Montana.
Oldacre, Angela Marie, University of Oklahoma, Cherokee Nation, Oklahoma.
O'Leary, Veronica Anne, University of North Carolina/Chapel Hill, Cheyenne River Sioux Tribe of the Cheyenne River Reservation, South Dakota.
Oxford, Dustin Joseph, A.T. Still University, Cherokee Nation, Oklahoma.
Oyebi, Surphina Ann, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Paduano, Pamela Diane, Glendale Community College, Navajo Nation, Arizona, New Mexico & Utah.
Page, Tyler Stephen, University of Oklahoma, Cherokee Nation, Oklahoma.
Palacol, Christie Kahikuonalani, Touro University, Comanche Nation, Oklahoma.
Palmer, Jason Eric, Spokane Falls Community College, Confederated Tribes of the Colville Reservation, Washington.
Parker, Mahate Ann, University of North Dakota, Chickasaw Nation, Oklahoma.
Pascoe, Vannessa Hochhalter, New York University, Oglala Sioux Tribe of the Pine Ridge Reservation, South Dakota.
Patton, Mary, Murray State College, Chickasaw Nation, Oklahoma.
Paul, Kimberly Lynn, University of Montana, Blackfeet Tribe of the Blackfeet Indian Reservation of Montana.
Pearish, Loni Dawn, Oklahoma State University, Cherokee Nation, Oklahoma.
Pearman, Zachary Brian, University of Wyoming, Cheyenne River Sioux Tribe of the Cheyenne River Reservation, South Dakota.
Pecos, Ida Marie, University of New Mexico/Albuquerque, Pueblo of Jemez, New Mexico.
Peltier, Luke Joseph, North Dakota State University, Turtle Mountain Band of Chippewa Indians of North Dakota.
Peltier, Rodrick Allan, North Dakota State University, Turtle Mountain Band of Chippewa Indians of North Dakota.
Peters, Aaron Lee, University of Alaska/Anchorage, Native Village of Ruby.
Petersen, Heather Rae, University of South Dakota, Oglala Sioux Tribe of the Pine Ridge Reservation, South Dakota.
Peterson, Jade Marie, University of Mary, Cheyenne River Sioux Tribe of the Cheyenne River Reservation, South Dakota.
Phelps, Nichole Marie, Northeastern State University, Cherokee Nation, Oklahoma.
Phillips, Lydia Elaine, Southwestern Oklahoma State University, Choctaw Nation of Oklahoma.
Pigeon, Marisa Kay, Minnesota West Community & Technical College, Sisseton-Wahpeton Sioux Tribe of the Lake Traverse Reservation, South Dakota.
Pletnikoff, Elise Marie, University of Washington, Sun'aq Tribe of Kodiak, (formerly Shoonaq' Tribe of Kodiak).
Poitra, Shonda Lee, Minot State University, Turtle Mountain Band of Chippewa Indians of North Dakota.
Pond, Leland James, Arizona School of Dentistry, Assiniboine & Sioux Tribes of the Fort Peck Indian Reservation, Montana.
Preston, Drew Alan, University of California/Los Angeles, Navajo Nation, Arizona, New Mexico & Utah.
Prettypaint, Debra Ann, University of Montana, Crow Tribe of Montana.
Price, Aaron Joseph, University of New Mexico/Albuquerque, Navajo Nation, Arizona, New Mexico & Utah.
Putnam, Sara Jane, University of Wisconsin, Stockbridge Munsee Community, Wisconsin.
Quillman, Steven Kurt, Tulsa Community College, Seminole Nation of Oklahoma.

Racehorse, Verna Lee, Boise State University, Shoshone-Bannock Tribes of the Fort Hall Reservation of Idaho.
Ragsdale, Allison Lynn, Evangel University, Cherokee Nation, Oklahoma.
Ramirez, Amanda Jo, Seminole Junior College, Muscogee (Creek) Nation, Oklahoma.
Ramone, Bernadette Nina, University of New Mexico/Albuquerque, Navajo Nation, Arizona, New Mexico & Utah.
Rasor, Joseph James, Midwestern University, Navajo Nation, Arizona, New Mexico & Utah.
Razote, Antoinette Jo, Eastern Washington University, Sisseton-Wahpeton Sioux Tribe of the Lake Traverse Reservation, South Dakota.
Redcorn, Moira Ambrose, Oklahoma State University, Osage Tribe, Oklahoma.
Redhouse, Brenda Lynn, Northern Arizona University, Navajo Nation, Arizona, New Mexico & Utah.
Reising, Kotanee Tenas, Medical College of Wisconsin, Menominee Indian Tribe of Wisconsin.
Rice, Charan Norwakis, Xavier University of Louisiana, Pawnee Nation of Oklahoma.
Richards, Matthew Douglas, Marquette University, Red Cliff Band of Lake Superior of Chippewa Indians of Wisconsin.
Rico, Jennifer Rebecca Rose, Oklahoma City University, Caddo Indian Tribe of Oklahoma.
Riffe, Evelyn Laura, University of Alaska, Native Village of Hooper Bay.
Riggs, Gwendelyn Dee, Northern Arizona University, Navajo Nation, Arizona, New Mexico & Utah.
Riggs, Jaclyn Nichole, St Louis University, Cheyenne-Arapaho Tribes of Oklahoma.
Rigsby, Carrieretha Joetta, Bacone College, Cherokee Nation, Oklahoma.
Risenhoover, Danny Joe, Bacone College, Choctaw Nation of Oklahoma.
Roberts, Sarah Whitney, Bacone College, Cherokee Nation, Oklahoma.
Robertson, Kandice Denae, East Central University, Choctaw Nation of Oklahoma.
Rodriguez, Suzanne Linette, Eastern Washington University, Pueblo of Isleta, New Mexico.
Rogers, Kalen Jared, University of Oklahoma, Chickasaw Nation, Oklahoma.
Rogers, Valerie Jean, Bacone College, Cherokee Nation, Oklahoma.
Romero, Teresa Beth, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.
Ross, Aaron Daniel, Southwestern Oklahoma State University, Cherokee Nation, Oklahoma.
Ross, David Byasa, Oklahoma State University, Cherokee Nation, Oklahoma.
Ross, Matthew, University of Southern California, Cherokee Nation, Oklahoma.
Rouillard, Allison Marie, University of North Dakota, Sisseton-Wahpeton Sioux Tribe of the Lake Traverse Reservation, South Dakota.
Rucker-Whytal, Amanda Anne, Kansas City University, Osage Tribe, Oklahoma,
Saladin, Elizabeth Jane, Howard University, Seminole Nation of Oklahoma.
Salois-Albert, Shaunda Marie, Walla Walla College, Confederated Salish & Kootenai of the Flathead Reservation, Montana.
Sanderson, Kendra Marie, University of Arizona, Navajo Nation, Arizona, New Mexico & Utah.
Sandoval, Kerri Dorea, Northern Arizona University, Navajo Nation, Arizona, New Mexico & Utah.
Sarter, Teresa Mae, Oregon State University, Central Council of the Tlingit & Haida Indian Tribes, Alaska.
Schmidt, Erin Michelle, University of Oklahoma, Muscogee (Creek) Nation, Oklahoma.
Schoemann, Lindsey Tanner, Oklahoma State University, Citizen Potawatomi Nation, Oklahoma.
Scott, Margaret Rochan, University of North Dakota, Spokane Tribe of the Spokane Reservation, Washington.
Sennett, Floy Lumae, Oklahoma Wesleyan University, Cherokee Nation, Oklahoma.
Shadaram, Sara Roya, University of Oklahoma, Cheyenne-Arapaho Tribes of Oklahoma.
Shepard, Cristopher Allan Joseph, University of Nevada/Las Vegas, Santee Sioux Nation.
Shipley-Skaggs, Amanda Marie, Southwestern Oklahoma State University, Cherokee Nation, Oklahoma.
Shirley, Jeremy, Mesa Community College, Navajo Nation, Arizona, New Mexico & Utah.
Sixkiller, Cheryl Lynn, University of Oklahoma, Cherokee Nation, Oklahoma.
Skeets, Jennifer A., University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Small, Shiloh Nicole, University of South Dakota, Northern Cheyenne Tribe of the Northern Cheyenne Indian Reservation, Montana.
Smith, Jana Renee, University of Oklahoma, Cherokee Nation, Oklahoma.
Smith, Lavonda, University of New Mexico/Gallup, Navajo Nation, Arizona, New Mexico & Utah.
Smith, Samantha Jenny, University of Alaska/Fairbanks, Navajo Nation, Arizona, New Mexico & Utah.
Snell, Deborah Dian, Northeastern State University, Cherokee Nation, Oklahoma.
Soliz, Narcisso, Southwestern Oklahoma State University, Rosebud Sioux Tribe of the Rosebud Indian Reservation, South Dakota.
Sorrell, Robin Lynn, Arizona State University, Navajo Nation, Arizona, New Mexico & Utah.
Spalding, Charles Scott, Arizona School of Dentistry, Sun'aq Tribe of Kodiak, (formerly Shoonaq' Tribe of Kodiak).
Sparkman, Madison Pauline, University of Oklahoma, Cherokee Nation, Oklahoma.
Stamile, Zachary Peter, Northeastern State University, Chickasaw Nation, Oklahoma.
Stevens, Anna Leone, Alliant International University, Sun'aq Tribe of Kodiak (formerly Shoonaq' Tribe of Kodiak).
Stevens, Erika S., Central Washington University, Native Village of Eagle.
Stickler, Desiree Nadine, University of New Mexico, Central Council of Tlingit & Haida Indian Tribes.
Stimson, Danielle Rain, Eastern Washington University, Blackfeet Tribe of the Blackfeet Indian Reservation of Montana.
Stitzer, Michael Eric, Mount Sinai University, Enterprise Rancheria of Maidu Indians of California.
Stone, Jennifer June, University of Oklahoma, Choctaw Nation of Oklahoma.
Strong, Charles Joseph, University of Texas at Austin, Chickasaw Nation, Oklahoma.
Sun Rhodes, Lisa Sky, University of Washington, Arapahoe Tribe of the Wind River Reservation, Wyoming.
Sweeney, Michael Aaron, Case Western Reserve University, Choctaw Nation of Oklahoma.
Tapp, Jamie Lynn, Southwestern Oklahoma State University, Chickasaw Nation, Oklahoma.
Tarango, Elena Marveya, Western College, lone Band of Miwok Indians of California.
Tarbell, Stephen Charles, University of Buffalo, St. Regis Band of Mohawk Indians of New York.
Taylor, Jennifer Elise, New York University, Pit River Tribe, California (includes, XL Ranch, Big Bend, Likely, Lookout, Montgomery Creek, and Roaring Creek Rancherias).
Taylor, Timothy Michael, Missouri Southern State College, Citizen Potawatomi Nation, Oklahoma.
Tedesco, Tomacita Feliz, University of New Mexico, Pueblo of Taos, New Mexico.

Teller, Terry Lee, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Tenoso, Olowan Dawn Clara, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Thomas, Levon Totsohnii, Massachusetts Institute of Technology, Navajo Nation, Arizona, New Mexico & Utah.
Thompson, Weston Dewey, Southwestern Oklahoma State University, Cherokee Nation, Oklahoma.
Thurmond-Montoya, Vivian Lynette, University of Alaska, Galena Village (aka Louden Village).
Tincher, Amber Nicole, University of North Dakota, Assiniboine & Sioux Tribes of the Fort Peck Indian Reservation, Montana.
Todachine, Katie Bah, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Toledo, Sherri J., Gateway Community College, Navajo Nation, Arizona, New Mexico & Utah.
Tom, Valora Jean, Texas Woman's University, Navajo Nation, Arizona, New Mexico & Utah.
Tonasket, Joleen Michele, Washington State University Intercollegiate College, Spokane Tribe of the Spokane Reservation, Washington.
Townsend, Travis J., University of New Mexico at Albuquerque, Pueblo of Acoma, New Mexico.
Tripp, Emilio Amos, Humboldt State University, Karuk Tribe of California.
Tuomi, Ashley Renee, Washington State University, Confederated Tribes of the Grand Ronde Community of Oregon.
Turner, Stephen Matthew, Bemidji State University, Minnesota Chippewa Tribe, Minnesota.
Tveit, Adrienne Hilda, Washington State University, Central Council of Tlingit & Haida Indian Tribes.
Uttchin, Venus, University of Oklahoma, Muscogee (Creek) Nation, Oklahoma.
Vandagriff, Katie Larue, University of Oklahoma, Cherokee Nation, Oklahoma.
Varnell, Cassidy Gertrude, University of Phoenix, Cherokee Nation, Oklahoma.
Vicenti, Darlene, University of New Mexico/Gallup, Zuni Tribe of the Zuni Reservation, New Mexico.
Vicenti, Vanessa Lynn, University of New Mexico/Albuquerque, Zuni Tribe of the Zuni Reservation, New Mexico.
Walker, Breanna Jo, Northeastern State University, Cherokee Nation, Oklahoma.
Walker, Lindsay Allison, University of North Carolina, Eastern Band of Cherokee Indians of North Carolina.
Walker, Marshall Austin, University of Oklahoma, Cherokee Nation, Oklahoma.
Wallace, Becky Lee, College of St. Catherine, Winnebago of Nebraska.
Wanna, Jessica Jean, Minnesota State University, Sisseton-Wahpeton Sioux Tribe of the Lake Traverse Reservation, South Dakota.
Ward, Jennifer Elaine, Kirksville College, Cherokee Nation, Oklahoma.
Ward, Micah N., University of Oklahoma, Citizen Potawatomi Nation, Oklahoma.
Ward, Rolanda Reason, University of Alaska/Anchorage, Egegik Village.
Waters, Jonathan Michael, University of Texas, Choctaw Nation of Oklahoma.
Watts, Brandi Kay, University of Oklahoma, Choctaw Nation of Oklahoma.
Watts, Candace Summer, Hampton University, Navajo Nation, Arizona, New Mexico & Utah.
Webster, Roxanne Dione, College of Saint Mary, Assiniboine & Sioux Tribes of the Fort Peck Indian Reservation, Montana.
Wells, Natasha Nicole, Colorado State University, Standing Rock Sioux Tribe of North & South Dakota.
Werner, Gwenlynn Laine, Arizona School of Dentistry, Navajo Nation, Arizona, New Mexico & Utah.
West, Latoya Ann, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Whistler, Brett Patrick, University of North Dakota, Citizen Potawatomi Nation, Oklahoma.
White, Christine Anne, University of Minnesota at Duluth, Sitka Tribe of Alaska.
White, Jenifer Lorraine, Oral Roberts University, Cherokee Nation, Oklahoma.
Whitehair, Orlantha, University of Arizona, Navajo Nation, Arizona, New Mexico & Utah.
Whitsitt, Adam Douglas, Midwestern University, Choctaw Nation of Oklahoma.
Wiley, Matthew Hallett, Oklahoma State University, Muscogee (Creek) Nation, Oklahoma.
Wilkerson, Thaddus Donavan, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah.
Wilkinson, Benjamin Bruce, University of North Dakota, Catawba Indian Tribe.
Williams, Clarrisa, University of Arizona, Navajo Nation, Arizona, New Mexico & Utah.
Williams, Jennifer Brooke, Washington State University, Choctaw Nation of Oklahoma.
Williams, Scott Bradley, University of Iowa, Cherokee Nation, Oklahoma.
Wilson, Lowery Elizabeth, University of Oklahoma, Cherokee Nation, Oklahoma.
Wilson, Patricia Kay, University of New Mexico/Gallup, Navajo Nation, Arizona, New Mexico & Utah.
Wilson, Sharon Jean, Northern Arizona University, Navajo Nation, Arizona, New Mexico & Utah.
Wilson-Idleman, Chase Te, University of Oklahoma, Choctaw Nation of Oklahoma.
Wind, Amber Rose, Oklahoma Baptist University, Seminole Nation of Oklahoma.
Winton, Lindsay Dallas, University of Oklahoma, Cherokee Nation, Oklahoma.
Wofford, Clifford Wendell, University of Oklahoma, United Keetoowah Band of Cherokee Indians in Oklahoma.
Woodral, Jaclyn Suzanne, Southeastern Oklahoma State University, Choctaw Nation of Oklahoma.
Woods, Tabatha Victoria, Northeastern State University, Cherokee Nation, Oklahoma.
Woodward, Amber Gail, University of Montana, Blackfeet Tribe of the Blackfeet Indian Reservation of Montana.
Woodward, Tiana Amanda, University of Oklahoma, Muscogee (Creek) Nation, Oklahoma.
Woosley, Thomas Martin, Northeastern State University, Cherokee Nation, Oklahoma.
Wright, Garrett Keith, University of Oklahoma, Cherokee Nation, Oklahoma.
Wright, Theodore Charles, University of Washington, Central Council of Tlingit & Haida Indian Tribes.
Yazzie, Celia Rose, University of New Mexico at Gallup, Navajo Nation, Arizona, New Mexico & Utah.
Yazzie, Delvin, University of Arizona, Navajo Nation, Arizona, New Mexico & Utah
Yazzie, Maria, University of New Mexico, Navajo Nation, Arizona, New Mexico & Utah
Yazzie, Vachera D., Northern Arizona University, Navajo Nation, Arizona, New Mexico & Utah.
Young, Naomi J., University of Arizona, Navajo Nation, Arizona, New Mexico & Utah.
Youngblood, Chase Culver, University of Oklahoma, Cherokee Nation, Oklahoma.
Zackery, Kathryn Sue, Oklahoma State University, Muscogee (Creek) Nation, Oklahoma.
Zeek, Courtney Mackenzie Joelle, Portland State University, Choctaw Nation of Oklahoma.
Zupan, Sherie Lee, University of North Dakota, Turtle Mountain Band of Chippewa Indians of North Dakota.

For Further Information Contact: The Indian Health Service Scholarship Branch, 801 Thompson Avenue, Suite 120, Rockville, Maryland 20852, Telephone: (301) 443–6197, Fax: (301) 443–6048.

Dated: March 26, 2007.

Charles. W. Grim,

Assistant Surgeon General, Director, Indian Health Service.

[FR Doc. 07–1634 Filed 4–3–07; 8:45 am]

BILLING CODE 4165–16–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Indian Health Service

[CFDA Number: 93.164]

Loan Repayment Program for Repayment of Health Professions Educational Loans; Announcement Type: Initial

Key Dates: January 19, 2007 first award cycle deadline date, September 30, 2007 entry on duty deadline date

I. Funding Opportunity Description

The Indian Health Service (IHS) estimated budget request for Fiscal Year (FY) 2007 includes $11,581,766 for the Indian Health Service (IHS) Loan Repayment Program (LRP) for health professional educational loans (undergraduate and graduate) in return for full-time clinical service in Indian health programs.

This program announcement is subject to the appropriation of funds. This notice is being published early to coincide with the recruitment activity on the IHS, which competes with other Government and private health management organizations to employ qualified health professionals.

This program is authorized by Section 108 of the Indian Health Care Improvement Act (IHCIA) as amended, 25 U.S.C. 1601 *et seq.* The IHS invites potential applicants to request an application for participation in the LRP.

II. Award Information

It is anticipated that $11,581,766 will be available to support approximately 250 competing awards averaging $46,300 per award for a two year contract. One year contract continuations will receive priority consideration in any award cycle. Applicants selected for participation in the FY 2007 program cycle will be expected to begin their service period no later than September 30, 2007.

III. Eligibility Information

1. Eligible Applicants

Pursuant to Section 108(b), to be eligible to participate in the LRP, an individual must:

(1)(A) Be enrolled—

(i) In a course of study or program in an accredited institution, as determined by the Secretary, within any State and be scheduled to complete such course of study in the same year such individual applies to participate in such program; or

(ii) In an approved graduate training program in a health profession; or

(B) Have a degree in a health profession and a license to practice in a state; and

(2)(A) Be eligible for, or hold an appointment as a Commissioned Officer in the Regular or Reserve Corps of the Public Health Service (PHS); or

(B) Be eligible for selection for service in the Regular or Reserve Corps of the (PHS); or

(C) Meet the professional standards for civil service employment in the IHS; or

(D) Be employed in an Indian health program without service obligation; and

(E) Submit to the Secretary an application for a contract to the Loan Repayment Program. The Secretary must approve the contract before the disbursement of loan repayments can be made to the participant. Participants will be required to fulfill their contract service agreements through full-time clinical practice at an Indian health program site determined by the Secretary. Loan repayment sites are characterized by physical, cultural, and professional isolation, and have histories of frequent staff turnover. All Indian health program sites are annually prioritized within the Agency by discipline, based on need or vacancy.

Section 108 of the IHCIA, as amended by Public Laws 100–713 and 102–573, authorizes the IHS LRP and provides in pertinent part as follows:

> (a)(1) The Secretary, acting through the Service, shall establish a program to be known as the Indian Health Service Loan Repayment Program (hereinafter referred to as the ''Loan Repayment Program'') in order to assure an adequate supply of trained health professionals necessary to maintain accreditation of, and provide health care services to Indians through, Indian health programs.

Section 4(n) of the IHCIA, as amended by the Indian Health Care Improvement Technical Corrections Act of 1996, Pub. L. 104–313, provides that:

> ''Health Profession'' means *allopathic medicine*, family medicine, internal medicine, pediatric, geriatric medicine, obstetrics and gynecology, podiatric medicine, nursing, public health nursing, dentistry, psychiatry, osteopathy, optometry, pharmacy, psychology, public health, social work, marriage and family therapy, chiropractic medicine, environmental health and engineering, and allied health profession, *or any other health profession*

For the purposes of this program, the term ''Indian health program'' is defined in Section 108(a)(2)(A), as follows:

(A) The term ''Indian health program'' means any health program or facility found, in whole or in part, by the Service for the benefit of Indians and administered—

(i) Directly by the Service;

(ii) By any Indian tribe or tribal or Indian organization pursuant to a contract under—

(I) The Indian Self-Determination Act, or

(II) Section 23 of the Act of April 30, 1908, (25 U.S.C. 47), popularly known as the Buy Indian Act; or

(iii) By an urban Indian organization pursuant to title V of this act.

Section 108 of the IHCIA, as amended by Public Laws 100–713 and 102–573, authorizes the IHS to determine specific health professions for which Indian Health Loan Repayment contracts will be awarded. The list of priority health professions that follow are based upon the needs of the IHS as well as upon the needs of the American Indians and Alaska Natives.

(a) *Medicine:* Allopathic and Osteopathic.

(b) *Nurse:* Associate and B.S. Degree.

(c) *Clinical Psychology:* Ph.D. only.

(d) *Social Work:* Masters level only.

(e) Chemical Dependency Counseling: Baccalaureate and Masters level.

(f) Dentistry.

(g) Dental Hygiene.

(h) Pharmacy: B.S., Pharm.D.

(i) Optometry.

(j) Physician Assistant.

(k) Advanced Practice Nurses: Nurse Practitioner, Certified Nurse Midwife, Registered Nurse Anesthetist (Priority consideration will be given to Registered Nurse Anesthetists.)

(l) Podiatry: D.P.M.

(m) Physical Rehabilitation Services: Physical Therapy, Occupational Therapy, Speech-Language Pathology, and Audiology: M.S. and D.P.T;

(n) Diagnostic Radiology Technology: Certificate, Associate, and B.S.

(o) Medical Technology: B.S., and Associate.

(p) Public Health Nutritionist/ Registered Dietitian.

(q) Engine (Environmental): B.S. (Engineers must provide environmental engineering services to be eligible).

(r) Environmental Health (Sanitarian): B.S.

(s) Health Records: R.H.I.T. and R.H.I.A.
(t) Respiratory Therapy.
(u) Ultrasonography.

2. Cost Sharing or Matching

Not applicable.

3. Other Requirements

Interested individuals are reminded that the list of eligible health and allied health professions is effective for applicants for FY 2007. These priorities will remain in effect until superseded.

IV. Application and Submission Information

1. Address To Request Application Package

Application materials may be obtained by calling or writing to the address below. *In addition, completed applications should be returned to:* IHS Loan Repayment Program, 801 Thompson Avenue, Suite 120, Rockville, Maryland 20852, PH: 301/443–3396 [between 8 a.m. and 5 p.m. (EST) Monday through Friday, except Federal holidays].

2. Content and Form of Application Submission

Applications must be submitted on the Form entitled ''Application for the Indian Health Service Loan Repayment Program,'' identified with the Office of Management and Budget approval number of OMB #0917–0014 (expires 12/31/08).

3. Submission Dates and Times

Completed applications may be submitted to the IHS Loan Repayment Program, 801 Thompson Avenue, Suite 120, Rockville, Maryland 20852. Applications for the FY 2007 LRP will be accepted and evaluated monthly beginning January 19, 2007 and will continue to be accepted each month thereafter until all funds are exhausted for FY 2007. Subsequently monthly deadline dates are scheduled for Friday of the second full week of each month.

Applications shall be considered as meeting the deadline if they are either:

(a) Received on or before the deadline date; or

(b) Sent on or before the deadline date. (Applicants should request a legibly dated U.S. Postal Service postmark or obtain a legibly dated receipt from a commercial carrier or U.S. Postal Service. Private metered postmarks are *not* acceptable as proof of timely mailing.)

Applications received after the monthly closing date will be held for consideration in the next monthly funding cycle. Applicants who do not receive funding by September 30, 2007, will be notified in writing.

4. Intergovernmental Review

This program is not subject to review under Executive Order 12372.

5. Funding Restrictions

Not applicable.

6. Other Submission Requirements

All applicants must sign and submit to the Secretary, a written contract agreeing to accept repayment of educational loans and to serve for the applicable period of obligated service in a priority site as determined by the Secretary, and submit a signed affidavit attesting to the fact that they have been informed of the relative merits of the U.S. PHS Commissioned Corps and the Civil Service as employment options.

V. Application Review Information

1. Criteria

The IHS has identified the positions in each Indian health program for which there is a need or vacancy and ranked those positions in order of priority by developing discipline-specific prioritized lists of sites. Ranking criteria for these sites include the following:

(a) Historically critical shortages caused by frequent staff turnover;

(b) Current unmatched vacancies in a Health Profession Discipline;

(c) Projected vacancies in a Health Profession Discipline;

(d) Ensuring that the staffing needs of Indian health programs administered by an Indian Tribe or Tribal or health organization receive consideration on an equal basis with programs that are administered directly by the Service;

(e) Giving priority to vacancies in Indian health programs that have a need for health professionals to provide health care services as a result of individuals having breached LRP contracts entered into under this section;

Consistent with this priority ranking, in determining applications to be approved and contracts to accept, the IHS will give priority to applications made by American Indians and Alaska Natives and to individuals recruited through the efforts of Indian Tribes or Tribal or Indian organizations;

2. Review and Selection Process

Loan Repayment Awards will be made only to those individuals serving at facilities which have a site score of 70 or above during the first and second quarters and the first month of the third quarter of FY 2007, if funding is available.

One or all of the following factors may be applicable to an applicant, and the applicant who has the most of these factors, all other criteria being equal, would be selected.

(a) An applicant's length of current employment in the IHS, Tribal, or urban program.

(b) Availability for service earlier than other applicants (first come, first served).

(c) Date the individual's application was received.

3. Anticipated Announcement and Award Dates

Not applicable.

VI. Award Administration Information

1. Award Notices

Notice of awards will be mailed on the last working day of each month. Once the applicant is approved for participation in the LRP, the applicant will receive confirmation of his/her loan repayment award and the duty site at which he/she will serve his/her loan repayment obligation.

2. Administrative and National Policy Requirements

Applicants may sign contractual agreements with the Secretary for 2 years. The IHS may repay all, or a portion of the applicant's health profession educational loans (undergraduate and graduate) for tuition expenses and reasonable educational and living expenses in amounts up to $20,000 per year for each year of contracted service. Payments will be made annually to the participant for the purpose of repaying his/her outstanding health profession educational loans. Payment of health profession education loans will be made to the participant within 120 days, from the date the contract become effective.

In addition to the loan repayments, participants are provided tax assistance payments in an amount not less than 20 percent and not more than 39 percent of the participant's total amount of loan repayments made for the taxable year involved. The loan repayments and the tax assistance payments are taxable income and will be reported to the Internal Revenue Service (IRS). The tax assistance payment will be paid to the IRS directly on the participant's behalf. LRP award recipients should be aware that the IRS may place them in a higher tax bracket than they would otherwise have been prior to their award.

3. Reporting

Any individual who enters this program and satisfactorily completes his or her obligated period of service may

apply to extend his/her contract on a year-by-year basis, as determined by the IHS. Participants extending their contracts may receive up to the maximum amount of $20,000 per year plus an additional 20 percent for Federal Withholding.

Any individual who owes an obligation for health professional service to the Federal Government, a State, or other entity is not eligible for the LRP unless the obligation will be completely satisfied before they begin service under this program.

VII. Agency Contacts

Please address inquiries to Ms. Jacqueline K. Santiago, Chief, IHS Loan Repayment Program, 801 Thompson Avenue, Suite 120, Rockville, Maryland 20852, PH: 301/443–3396 [between 8 a.m. and 5 p.m. (EST) Monday through Friday, except Federal holidays].

VIII. Other Information

IHS Area Offices and Service Units that are financially able are authorized to provide additional funding to make awards to applicants in the LRP, but not to exceed $35,000 a year plus tax assistance. All additional funding must be made in accordance with the priority system outlined below. Health professions given priority for selection above the $20,000 threshold are those identified as meeting the criteria in 25 U.S.C. 1616a(g)(2)(A) which provides that the Secretary shall consider the extent to which each such determination—

(i) Affects the ability of the Secretary to maximize the number of contracts that can be provided under the Loan Repayment Program from the amounts appropriated for such contracts;

(ii) Provides an incentive to serve in Indian health programs with the greatest shortages of health professionals; and

(iii) Provides an incentive with respect to the health professional involved remaining in an Indian health program with such a health professional shortage, and continuing to provide primary health services, after the completion of the period of obligated service under the Loan Repayment Program.

Contracts may be awarded to those who are available for service no later than September 30, 2007, and must be in compliance with any limits in the appropriation and Section 108 of the Indian Health Care Improvement Act not to exceed the amount authorized in the IHS appropriation (up to $27,000,000 for FY 2007). In order to ensure compliance with the statutes, Area Office or Service Units providing additional funding under this section are responsible for notifying the Loan Repayment Office of such payments before funding is offered to the LRP participant.

Should an IHS Area Office contribute to the LRP, those funds will be used for only those sites located in that Area. Those sites will retain their relative ranking from the national site-ranking list. For example, the Albuquerque Area Office identifies supplemental monies for dentists. Only the dental positions within the Albuquerque Area will be funded with the supplemental monies consistent with the national ranking and site index within that Area.

Should an IHS Service Unit contribute to the LRP, those funds will be used for only those sites located in that Service Unit. Those sites will retain their relative ranking from the national site-ranking list. For example, Chinle Service Unit identifies supplemental monies for pharmacists. The Chinle Service Unit consists of two facilities, namely the Chinle Comprehensive Health Care Facility and the Tsaile PHS Indian Health Center. The national ranking will be used for the Chinle Comprehensive Health Care Facility (Score = 44) and the Tsaile PHS Indian Health Center (Score = 46). With a score of 46, the Tsaile PHS Indian Health Center would receive priority over the Chinle Comprehensive Health Care Facility.

Dated: March 26, 2007.

Charles W. Grim,

Assistant Surgeon General, Director, Indian Health Service.

[FR Doc. 07–1635 Filed 4–3–07; 8:45 am]

BILLING CODE 4165–16–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Substance Abuse and Mental Health Services Administration

Agency Information Collection Activities: Proposed Collection; Comment Request

In compliance with Section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995 concerning opportunity for public comment on proposed collections of information, the Substance Abuse and Mental Health Services Administration (SAMHSA) will publish periodic summaries of proposed projects. To request more information on the proposed projects or to obtain a copy of the information collection plans, call the SAMHSA Reports Clearance Officer on (240) 276–1243.

Comments are invited on: (a) Whether the proposed collections of information are necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the proposed collection of information; (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 through the use of automated collection techniques or other forms of information technology.

Proposed Project: Confidentiality of Alcohol and Drug Abuse Patient Records—(OMB No. 0930–0092)—Revision

Statute (42 U.S.C. 290dd–2) and regulations (42 CFR part 2) require federally conducted, regulated, or directly or indirectly assisted alcohol and drug abuse programs to keep alcohol and drug abuse patient records confidential. Information requirements are (1) written disclosure to patients about Federal laws and regulations that protect the confidentiality of each patient, and (2) documenting ''medical personnel'' status of recipients of a disclosure to meet a medical emergency. Annual burden estimates for these requirements are summarized in the table below:

ANNUALIZED BURDEN ESTIMATES

	Annual Number of respondents [1]	Responses per respondent	Total responses	Hours per response	Total hour burden
Disclosure					
42 CFR 2.22	10,629	174	[2] 1,849,548	.20	369,910
Recordkeeping					
42 CFR 2.51	10,629	2	21,258	.26	5,527
Total	10,629		1,870,806		375,437

[1] The number of publicly funded alcohol and drug facilities from SAMHSA's 2005 National Survey of Substance Abuse Treatment Services (N–SSATS).
[2] The number of treatment admissions from SAMHSA's 2005 Treatment Episode Data Set (TEDS).

Send comments to Summer King, SAMHSA Reports Clearance Officer, Room 7–1044, One Choke Cherry Road, Rockville, MD 20857. Written comments should be received within 60 days of this notice.

Dated: March 28, 2007.

Elaine Parry,

Acting Director, Office of Program Services.

[FR Doc. E7–6272 Filed 4–3–07; 8:45 am]

BILLING CODE 4162–20–P

DEPARTMENT OF HOMELAND SECURITY

[Docket No. FLETC–2007–0001]

Federal Law Enforcement Training Center; Advisory Committee to the Office of State and Local Training

AGENCY: Federal Law Enforcement Training Center (FLETC), DHS.

ACTION: Committee Management; Notice of Federal Advisory Committee Meeting.

SUMMARY: The Advisory Committee to the Office of State and Local Training (OSL) will meet on April 25, 2007, in Brunswick, GA. The meeting will be open to the public.

DATES: The Advisory Committee to the Office of State and Local Training will meet Wednesday, April 25, 2007, from 8 a.m. to 4 p.m. Please note that the meeting may close early if the committee has completed its business.

ADDRESSES: The meeting will be held at the Holiday Inn Hotel and Suites, 138 Glynco Parkway, Brunswick, GA. Send written material, comments, and/or requests to make an oral presentation to the contact person listed below by April 6th. Requests to have a copy of your material distributed to each member of the committee prior to the meeting should reach the contact person at the address below by April 6th. Comments must be identified by FLETC–2007–0001 and may be submitted by *one* of the following methods:

- Federal eRulemaking Portal: *http://www.regulations.gov.* Follow the instructions for submitting comments.
- E-mail: *reba.fischer@dhs.gov.* Include docket number in the subject line of the message.
- Fax: (912) 267–3531. (Not a toll-free number).
- Mail: Reba Fischer, Designated Federal Officer (DFO), Federal Law Enforcement Training Center, Department of Homeland Security, 1131 Chapel Crossing Road, Townhouse 396, Glynco, GA 31524.

Instructions: All submissions received must include the words ''Department of Homeland Security'' and the docket number for this action. Comments received will be posted without alteration at *www.regulations.gov*, including any personal information provided.

Docket: For access to the docket to read background documents or comments received by the Advisory Committee to the Office of State and Local Training, go to *www.regulations.gov*.

FOR FURTHER INFORMATION CONTACT: Reba Fischer, Designated Federal Officer, Federal Law Enforcement Training Center, Department of Homeland Security, 1131 Chapel Crossing Road, Townhouse 396, Glynco, GA 31524; (912) 267–2343; *reba.fischer@dhs.gov.*

SUPPLEMENTARY INFORMATION: Notice of this meeting is given under the Federal Advisory Committee Act, 5 U.S.C. App. (Pub. L. 92–463). The mission of the Advisory Committee to the Office of State and Local Training is to advise and make recommendations on matters relating to the selection, development, content and delivery of training services by the OSL/FLETC to its state, local, campus, and tribal law enforcement customers.

Draft Agenda:

The draft agenda for this meeting includes briefings to update committee members on OSL and FLETC training initiatives and discussion to identify training needs having a direct impact on state, local, campus, and tribal law enforcement officers.

Procedural:

This meeting is open to the public. Please note that the meeting may close early if all business is finished.

Visitors must pre-register attendance to ensure adequate seating. Please provide your name and telephone number by close of business on April 6, 2007, to Reba Fischer (contact information above).

Information on Services for Individuals with Disabilities: For information on facilities or services for individuals with disabilities or to request special assistance at the meeting, contact Reba Fischer as soon as possible.

Dated: March 23, 2007.

Denise L. Franklin,

Acting Deputy Assistant Director, Office of State and Local Law Enforcement Training.

[FR Doc. 07–1644 Filed 4–3–07; 8:45 am]

BILLING CODE 4810–32–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5123–N–08]

Notice of Proposed Information Collection for Public Comment on the Humidity Monitoring Survey

AGENCY: Office of the Policy Development and Research, HUD.

ACTION: Notice.

SUMMARY: The proposed information collection requirement described below will be submitted to the Office of Management and Budget (OMB) for review, as required by the Paperwork

Reduction Act. The Department is soliciting public comments on the subject proposal.

DATES: *Comments Due Date:* June 4, 2007.

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB Control Number and should be sent to: Reports Management Liaison Officer, Office of Policy Development and Research, Department of Housing and Urban Development, 451 7th Street, SW., Room 8234, Washington, DC 20410–5000.

FOR FURTHER INFORMATION CONTACT: Mr. Michael Blanford, Research Engineer, Office of Policy Development and Research, Department of Housing and Urban Development, 451 7th Street, SW., Room 8134, Washington, DC 20410–5000. Call (202) 402–5728 for copies of the proposed forms and other available documents. (This is not a toll-free number).

SUPPLEMENTARY INFORMATION: The Department will submit 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 of information 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 through 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 Proposal: Humidity Monitoring Survey.

Description of the need for the information and proposed use: This request is for the clearance of a survey instrument designed to measure the humidity levels in single family residences. The purpose of the survey is: (1) Collect moisture load data to support research to better understand the impact of moisture on the durability of homes; (2) Support the development of design criteria, such as ASHRAE Standard 160P, that will minimize durability problems associated with high moisture levels; (3) Investigate the influence of the interior and exterior conditions on the moisture level of typical single family detached homes.

OMB Approval Number: Pending OMB approval.

Agency form numbers: None.

Members of Affected Public: Individuals.

Estimation of the total number of hours needed to prepare the information collection including number of respondents, frequency of response, and hours of response: 70 individuals will be surveyed in person. Average time to complete the survey is 20 minutes. Respondents will be contacted three times, once every six months. Total burden hours are 70.

Status of the proposed information collection: New.

Authority: Section 3506 of the Paperwork Reduction Act of 1995, 44 U.S.C. Chapter 35, as amended.

Dated: March 29, 2007.

Darlene F. Williams,

Assistant Secretary for Policy Development and Research.

[FR Doc. E7–6226 Filed 4–3–07; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5123–N–09]

Notice of Proposed Information Collection for Public Comment on the Final Evaluation of the Moving to Opportunity Program

AGENCY: Office of the Policy Development and Research, HUD.

ACTION: Notice.

SUMMARY: The proposed information collection requirement described below will be submitted to the Office of Management and Budget (OMB) for review, as required by the Paperwork Reduction Act. The Department is soliciting public comments on the subject proposal.

DATES: *Comments Due Date:* June 4, 2007.

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB Control Number and should be sent to: Reports Liaison Officer, Office of Policy Development and Research, Department of Housing and Urban Development, 451 7th Street, SW., Room 8234, Washington, DC 20410.

FOR FURTHER INFORMATION CONTACT: Todd M. Richardson, Program Evaluation Division, Policy Development and Research, Department of Housing and Urban Development, 451 7th Street, SW., Room 8140, Washington, DC 20410–5000. Call (202) 402–5706 (this is not a toll-free number) or *Todd_Richardson@HUD.GOV* for copies of the proposed forms and other available documents.

SUPPLEMENTARY INFORMATION: The Department will submit 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 of information 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 through 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 Proposal: Final Evaluation of the Moving to Opportunity (MTO) Program.

Description of the need for the information and proposed use: This request is for the clearance of several survey instruments for the Final Evaluation of the Moving to Opportunity (MTO) demonstration program. Authorized by Congress in the Housing and Community Development Act of 1992, MTO is a unique experimental research demonstration designed to learn whether moving from a high-poverty neighborhood to a low-poverty neighborhood significantly improves the social and economic prospects of poor families. Families living in high poverty public and assisted housing in Baltimore, Boston, Chicago, Los Angeles and New York who applied for MTO were randomly assigned into two treatment groups and one control group between 1994 and 1998. Families assigned to the treatment groups were provided Section 8 to allow them to move out of the high poverty developments. Families in one of the

treatment groups received intensive mobility counseling and were required to lease a unit in a neighborhood with less than ten percent poverty. The other treatment group families could lease a unit wherever they chose, but only received the normal housing authority counseling. Those families assigned to the control group did not receive any Section 8 assistance but continued to receive project-based assistance.

This data collection is necessary to measure impacts and mediators approximately 10 to 14 years after families were randomly assigned to the two treatment groups and the control group. The data are planned to be collected for the following primary outcome domains: housing mobility and assistance; neighborhoods and social networks, adult education, employment and earnings; household income and cash assistance; adult, youth, and child physical and mental health; youth and child emotional and social well-being, including delinquency and risky behavior; and youth and child educational performance.

Interviews are estimated to be completed for 3,900 adult heads of household using the adult interview guide and approximately 5,800 youth between the ages of 10 and 20 using the youth interview guide. The youth and children noted above will be administered a math and reading achievement assessment. Subject to final decisions by the research team and HUD, as well as Institutional Review Board approval, the interviews will also include collection of biomarker data via finger pricks to obtain dried blood spots of MTO participants. All interviewers and testing will be conducted in-person or on the telephone by interviewers using computer-assisted personal interviewing (CAPI) or computer-assisted telephone interviewing software to directly input the data into a computer. Incentive payments will be made to respondents participating in this survey in order to ensure a high response rate. Data gathered will be used by the National Bureau of Economic Research to prepare a report to HUD on the long-term impacts of MTO. Subject to maintaining the privacy and confidentiality of respondents, the data collected will also be used by academics and HUD policy analysts to further explore what specific neighborhood mediating factors contribute to the neighborhood impact on outcomes for families and children. The information will be used by HUD and Congress to guide future housing policy in many areas, including housing mobility assistance and the location and concentration of assisted housing.

OMB Control Number: Pending approval.

Agency form numbers: None.

Members of Affected Public: Individuals and Households.

Estimation of the total number of hours needed to prepare the information collection including number of respondents, frequency of response, and hours of response: 3,900 adults at 75 minutes; 5,800 youth with 45 minute survey and 45 minute achievement test. One-time response, total 12,910 reporting burden hours.

Status of the proposed information collection: New.

Authority: Section 3506 of the Paperwork Reduction Act of 1995, 44 U.S.C. Chapter 35, as amended.

Dated: March 29, 2007.

Darlene F. Williams,

Assistant Secretary for Policy Development and Research.

[FR Doc. E7–6227 Filed 4–3–07; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

Receipt of Applications for Permit

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of receipt of applications for permit.

SUMMARY: The public is invited to comment on the following applications to conduct certain activities with endangered species and marine mammals.

DATES: Written data, comments or requests must be received by May 4, 2007.

ADDRESSES: Documents and other information submitted with these applications are available for review, subject to the requirements of the Privacy Act and Freedom of Information Act, by any party who submits a written request for a copy of such documents within 30 days of the date of publication of this notice to: U.S. Fish and Wildlife Service, Division of Management Authority, 4401 North Fairfax Drive, Room 700, Arlington, Virginia 22203; fax 703/358–2281.

FOR FURTHER INFORMATION CONTACT: Division of Management Authority, telephone 703/358–2104.

SUPPLEMENTARY INFORMATION:

Endangered Species

The public is invited to comment on the following applications for a permit to conduct certain activities with endangered species. This notice is provided pursuant to Section 10(c) of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*). Written data, comments, or requests for copies of these complete applications should be submitted to the Director (address above).

Applicant: Devon E. Pearse, NOAA-National Marine Fisheries Service, Southwest Fisheries Science Center, Santa Cruz, CA, PRT–135127.

The applicant requests a permit to import biological samples from Orinoco crocodiles (*Crocodylus intermedius*) for the purpose of enhancement of the species through scientific research. This notification covers activities conducted by the applicant for a five-year period.

Applicant: Zoological Society of San Diego, San Diego, CA, PRT–148347.

The applicant requests a permit to export biological samples from Southern white rhinoceros (*Ceratotherium simum simum*) and Asian tapir (*Tapirus indicus*) for the purpose of enhancement of the species through scientific research. This notification covers activities conducted by the applicant for a five-year period.

Applicant: Zoological Society of San Diego, San Diego, CA, PRT–149091.

The applicant requests a permit to export two live male California condors (*Gymnogyps californianus*) to the Chapultepec Zoo, Mexico for the purpose of enhancement of the survival of the species.

Applicant: Milwaukee County Zoological Gardens, Milwaukee, WI, PRT–149077.

The applicant requests a permit to export one male captive-born Central American tapir (*Tapirus bairdii*) to the Africam Safari Zoo, Mexico for the purpose of enhancement of the species through captive breeding and conservation education.

Applicant: Laurie A. Cotroneo, Drexel University, Pennsylvania, PA, PRT–149837.

The applicant requests a permit to import biological samples from American crocodile (*Crocodylus acutus*) for the purpose of enhancement of the species through scientific research. This notification covers activities conducted by the applicant for a five-year period.

Applicant: Wesley A. Miner, Jacksonville, FL, PRT–148576.

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa,

for the purpose of enhancement of the survival of the species.

Applicant: Darrel J. Steffy, Reamstown, PA, PRT–147960.

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

Applicant: Academy of Natural Sciences of Philadelphia, Philadelphia, PA, PRT–678963.

The applicant requests a renewal of their permit to export and re-import non-living museum specimens of endangered and threatened species of plants and animals previously accessioned into the applicant's collection for scientific research. This notification covers activities to be conducted by the applicant over a five-year period.

Endangered Marine Mammals and Marine Mammals

The public is invited to comment on the following applications for a permit to conduct certain activities with endangered marine mammals and marine mammals. The applications were submitted to satisfy requirements of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*) and the Marine Mammal Protection Act of 1972, as amended (16 U.S.C. 1361 *et seq.*), and the regulations governing endangered species (50 CFR part 17) and marine mammals (50 CFR part 18). Written data, comments, or requests for copies of the complete applications or requests for a public hearing on these applications should be submitted to the Director (address above). Anyone requesting a hearing should give specific reasons why a hearing would be appropriate. The holding of such a hearing is at the discretion of the Director.

Applicant: Edward Keith, NOVA Southeastern University, Dania Beach, FL, PRT–134165.

The applicant requests a permit to take captive-held and wild Florida manatees (*Trichechus manatus latirostris*) using sonar forward looking fishfinder devices for the purpose of scientific research. This notification covers activities to be conducted by the applicant over a five-year period.

Concurrent with the publication of this notice in the **Federal Register**, the Division of Management Authority is forwarding copies of the above applications to the Marine Mammal Commission and the Committee of Scientific Advisors for their review.

Applicant: Chase Fulcher, Henderson, KY, PRT–149169.

The applicant requests a permit to import a polar bear (*Ursus maritimus*) sport hunted from the Lancaster Sound polar bear population in Canada for personal, noncommercial use.

Dated: March 23, 2007.

Monica Farris,

Senior Permit Biologist, Branch of Permits, Division of Management Authority.

[FR Doc. E7–6260 Filed 4–3–07; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[AA–74591; AK–964–1410–KC–P]

Alaska Native Claims Selection

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of decision approving lands for conveyance.

SUMMARY: As required by 43 CFR 2650.7(d), notice is hereby given that an appealable decision approving the subsurface estate in certain lands for conveyance pursuant to the Alaska National Interest Lands Conservation Act will be issued to Bristol Bay Native Corporation. The lands are in the vicinity of Pedro Bay, Alaska, and are located in:

Seward Meridian, Alaska

T. 6 S., R. 27 W., Sec. 6.
Containing 582.58 acres.
T. 6 S., R. 28 W., Secs. 1, 11, and 12.
Containing 1,657.42 acres.
Aggregating 2,240.00 acres.

Notice of the decision will also be published four times in the Anchorage Daily News.

DATES: The time limits for filing an appeal are:

1. Any party claiming a property interest which is adversely affected by the decision shall have until May 4, 2007 to file an appeal.

2. Parties receiving service of the decision by certified mail shall have 30 days from the date of receipt to file an appeal.

Parties who do not file an appeal in accordance with the requirements of 43 CFR part 4, subpart E, shall be deemed to have waived their rights.

ADDRESSES: A copy of the decision may be obtained from: Bureau of Land Management, Alaska State Office, 222 West Seventh Avenue, #13, Anchorage, Alaska 99513–7504.

FOR FURTHER INFORMATION CONTACT: The Bureau of Land Management by phone at 907–271–5960, or by e-mail at *ak.blm.conveyance@ak.blm.gov.* Persons who use a telecommunication device (TTD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8330, 24 hours a day, seven days a week, to contact the Bureau of Land Management.

John Leaf,

Land Law Examiner, Branch of Adjudication II.

[FR Doc. E7–6264 Filed 4–3–07; 8:45 am]

BILLING CODE 4310–$$–P

INTERNATIONAL TRADE COMMISSION

[Investigation No. 731–TA–706 (Second Review)]

Canned Pineapple Fruit From Thailand

Determination

On the basis of the record [1] developed in the subject five-year review, the United States International Trade Commission (Commission) determines, pursuant to section 751(c) of the Tariff Act of 1930 (19 U.S.C. 1675(c)) (the Act), that revocation of the antidumping duty order on canned pineapple fruit from Thailand would be likely to lead to continuation or recurrence of material injury to an industry in the United States within a reasonably foreseeable time.[2]

Background

The Commission instituted this review on April 3, 2006 (71 FR 16585) and determined on July 7, 2006 that it would conduct a full review (71 FR 47523, August 17, 2006). Notice of the scheduling of the Commission's review 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 notice in the **Federal Register** on August 8, 2006 (71 FR 45073). The hearing was held in Washington, DC, on January 18, 2007, and all persons who requested the opportunity were permitted to appear in person or by counsel.

The Commission transmitted its determination in this review to the Secretary of Commerce on March 29, 2007. The views of the Commission are

[1] The record is defined in sec. 207.2(f) of the Commission's Rules of Practice and Procedure (19 CFR 207.2(f)).

[2] Commissioners Irving A. Williamson and Dean A. Pinkert did not participate.

contained in USITC Publication 3911 (March 2007), entitled Canned Pineapple Fruit from Thailand (Inv. No. 731–TA–706 (Second Review)).

Issued: March 30, 2007.

By order of the Commission.

Marilyn R. Abbott,

Secretary to the Commission.

[FR Doc. E7–6278 Filed 4–3–07; 8:45 am]

BILLING CODE 7020–02–P

DEPARTMENT OF LABOR

Office of the Secretary

Submission for OMB Review: Comment Request

March 30, 2007.

The Department of Labor (DOL) has submitted the following public information collection request (ICR) to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995 (Pub. L. 104–13, 44 U.S.C. Chapter 35). A copy of this ICR, with applicable supporting documentation, may be obtained at *http://www.reginfo.gov/public/do/PRAMain*, or contact Ira Mills on 202–693–4122 (this is not a toll-free number) or e-mail: *Mills.Ira@dol.gov*.

Comments should be sent to the Office of Information and Regulatory Affairs, Attn: OMB Desk Officer for U.S. Department of Labor/Employment and Training Administration (ETA), Office of Management and Budget, Room 10235, Washington, DC 20503, 202–395–7316 (this is not a toll free number), within 30 days from the date of this publication in the **Federal Register**.

The OMB is particularly interested in comments which:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
- Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
- Enhance the quality, utility and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Agency: Employment and Training Administration.

Type of Review: Extension without change of a currently approved collection.

Title: Benefit Rights and Experience Report.

OMB Number: 1205—0177.

Frequency: Quarterly.

Affected Public: State, Local, or Tribal Government.

Type of Response: Reporting.

Number of Respondents: 53.

Annual Responses: 216.

Average Response time: 30 minutes.

Total Annual Burden Hours: 108.

Total Annualized Capital/Startup Costs: 0.

Total Annual Costs (operating/maintaining systems or purchasing services): 0.

Description: This information collection provides information used in solvency studies, in budgeting projections and for evaluation of adequacy of benefit formulae to analyze effects of proposed changes in state laws.

Ira L. Mills,

Departmental Clearance Officer/Team Leader.

[FR Doc. E7–6252 Filed 4–3–07; 8:45 am]

BILLING CODE 4510–30–P

DEPARTMENT OF LABOR

Employee Benefits Security Administration

Prohibited Transaction Exemption (PTE) 2007–05; Exemption Application No. D–11370; Amendment to PTE 2000–58, 65 FR 67765 (November 13, 2000) and PTE 2002–41, 67 FR 54487 (August 22, 2002) Involving Bear, Stearns & Co. Inc., Prudential Securities Incorporated et al. To Add Dominion Bond Rating Service Limited and Dominion Bond Rating Service, Inc. to the Definition of ''Rating Agency''

AGENCY: Employee Benefits Security Administration, U.S. Department of Labor (the Department).

ACTION: Notice of technical correction.

On March 20, 2007, the Department published PTE 2007–05 in the **Federal Register** at 72 FR 13130. PTE 2007–05 expands the definition of ''Rating Agency'' in section III.X of the Underwriter Exemptions to include Dominion Bond Rating Service Limited and Dominion Bond Rating Service, Inc. The Underwriter Exemptions are individual exemptions that provide relief for the origination and operation of certain asset pool investment trusts and the acquisition, holding and disposition by employee benefit plans of certain asset-backed, pass-through certificates representing undivided interests in those investment trusts, and also provided the same individual exemptive relief to: Deutsche Bank A.G., New York Branch and Deutsche Morgan Grenfell/C.J. Lawrence Inc., Final Authorization Number (FAN) 97–03E (December 9, 1996); Credit Lyonnais Securities (USA) Inc., FAN 97–21E (September 10, 1997); ABN AMRO Inc., FAN 98–08E (April 27, 1998); Ironwood Capital Partners Ltd., FAN 99–31E (December 20, 1999) (supersedes FAN 97–02E (November 25, 1996)); William J. Mayer Securities LLC, FAN 01–25E (October 15, 2001); Raymond James & Associates Inc. & Raymond James Financial Inc., FAN 03–07E (June 14, 2003); WAMU Capital Corporation, FAN 03–14E (August 24, 2003); and Terwin Capital LLC, FAN 04–16E (August 18, 2004); which received the approval of the Department to engage in transactions substantially similar to the transactions described in the Underwriter Exemptions pursuant to PTE 96–62, 61 FR 39988 (July 31, 1996).

In order to correct an inadvertent omission, the Department is adopting a technical correction to the final amendment. As corrected, at page 13130 of the notice granting the final amendment, the following organization and Final Authorization Number (FAN) is included in the list of organizations the Department is also granting individual exemptive relief for, after the phrase ''(August 24, 2003);'' ''Barclays Bank PLC & Barclays Capital Inc., FAN 04–03E (February 4, 2004);''.

Subsequent to publication of the final amendment, the Department was informed that, effective January 22, 2007, Dominion Bond Rating Service Limited changed its name to ''DBRS Limited,'' and Dominion Bond Rating Service, Inc. changed its name to ''DBRS, Inc.'' These are name changes only. There has been no change in the corporate structure or business activities of DBRS Limited and DBRS, Inc.

FOR FURTHER INFORMATION CONTACT: Ms. Wendy McColough of the Department at (202) 693–8553. (This is not a toll-free number.)

Signed at Washington, DC, this 29th day of March, 2007.

Ivan L. Strasfeld,

Director of Exemption Determinations, Employee Benefits Security Administration, U.S. Department of Labor.

[FR Doc. E7–6216 Filed 4–3–07; 8:45 am]

BILLING CODE 4510–29–P

DEPARTMENT OF LABOR

Employment and Training Administration

Investigations Regarding Certifications of Eligibility To Apply for Worker Adjustment Assistance and Alternative Trade Adjustment Assistance

Petitions have been filed with the Secretary of Labor under Section 221(a) of the Trade Act of 1974 (''the Act'') and are identified in the Appendix to this notice. Upon receipt of these petitions, the Director of the Division of Trade Adjustment Assistance, Employment and Training Administration, has instituted investigations pursuant to Section 221(a) of the Act.

The purpose of each of the investigations is to determine whether the workers are eligible to apply for adjustment assistance under Title II, Chapter 2, of the Act. The investigations will further relate, as appropriate, to the determination of the date on which total or partial separations began or threatened to begin and the subdivision of the firm involved.

The petitioners or any other persons showing a substantial interest in the subject matter of the investigations may request a public hearing, provided such request is filed in writing with the Director, Division of Trade Adjustment Assistance, at the address shown below, not later than April 16, 2007.

Interested persons are invited to submit written comments regarding the subject matter of the investigations to the Director, Division of Trade Adjustment Assistance, at the address shown below, not later than April 16, 2007.

The petitions filed in this case are available for inspection at the Office of the Director, Division of Trade Adjustment Assistance, Employment and Training Administration, U.S. Department of Labor, Room C–5311, 200 Constitution Avenue, NW., Washington, DC 20210.

Signed at Washington, DC, this 29th day of March 2007.

Ralph DiBattista,

Director, Division of Trade Adjustment Assistance.

APPENDIX

[TAA petitions instituted between 3/19/07 and 3/23/07]

TA–W	Subject firm (petitioners)	Location	Date of institution	Date of petition
61132	Dusenbery Worldwide (IBT)	Randolph, NJ	03/19/07	03/16/07
61133	Foundation Works Inc (Comp)	Cottage Grove, OR	03/19/07	03/14/07
61134	National Textiles (Sara Lee) (Wkrs)	Winston-Salem, NC	03/19/07	03/06/07
61135	Williamson and Company (State)	Greer, SC	03/19/07	03/15/07
61136	Electric Mills Kentucky EMK (Wkrs)	Burkesville, KY	03/19/07	03/16/07
61137	AAR Cargo Systems (UAW)	Livonia, MI	03/19/07	03/14/07
61138	Associated Spring, Barnes Group (UAW)	Saline, MI	03/19/07	03/14/07
61139	Steward Advanced Materials (Comp)	Chattanooga, TN	03/19/07	03/13/07
61140	Konica Minolta Graphic Imaging USA Inc (Comp)	Glen Cove, NY	03/19/07	03/12/07
61141	New ADS Marlin Corporation (Comp)	Long Island City, NY	03/19/07	03/15/07
61142	Alcatel Lucent (IBEW)	Columbus, OH	03/19/07	03/10/07
61143	DeMag Plastics (Wkrs)	Strongville, OH	03/20/07	03/09/07
61144	Royal Home Fashions (Comp)	Durham, NC	03/20/07	02/14/07
61145	Enhanced Manufacturing Solutions LLC (Comp)	Amherst, NY	03/20/07	02/28/07
61146	Watson Laboratories, Inc (Wkrs)	Phoenix, AZ	03/20/07	03/08/07
61147	Eastman Kodak (Wkrs)	Rochester, NY	03/20/07	03/14/07
61148	Russell Corporation, Plant #10 (Comp)	Alexander City, AL	03/20/07	03/19/07
61149	Johnson Controls (Wkrs)	Fullerton, CA	03/20/07	03/19/07
61150	Boise Cascade LLC (AWPPW)	Salem, OR	03/20/07	03/19/07
61151	Autoliv (Comp)	Madisonville, KY	03/20/07	03/19/07
61152	Precision Laser Inc (Comp)	High Point, NC	03/20/07	03/19/07
61153	Lenovo (Wkrs)	Reseach Triangle Park, NC	03/20/07	03/17/07
61154	Quaker Narrow Fabrics (Wkrs)	Milton, PA	03/20/07	03/19/07
61155	Pine Hosiery Mills Inc (Comp)	Ether, NC	03/20/07	03/15/07
61156	Classic Tool Inc (Wkrs)	Saegertown, PA	03/20/07	03/15/07
61157	Visteon Systems LLC (Comp)	Connersville, IN	03/20/07	03/19/07
61158	Jeld Wen Interior Division (Wkrs)	Chiloquin, OR	03/21/07	03/16/07
61159	Sony (Wkrs)	Mt. Pleasant, PA	03/21/07	03/20/07
61160	Bruce Plastics Inc (Comp)	Pittsburgh, PA	03/21/07	03/20/07
61161	Indalex Solutions (IBC)	Watsonville, CA	03/21/07	03/20/07
61162	Hoffman LaRoche (State)	Nutley, NJ	03/21/07	03/20/07
61163	Springs Global (Comp)	Calhoun, GA	03/21/07	03/21/07
61164	Intel Coproration (Wkrs)	Rio Rancho, NM	03/22/07	03/22/07
61165	Carhartt Inc Autopocket Facililty (Comp)	Madisonville, KY	03/22/07	03/21/07
61166	Carhartt Inc Sewing Facility (Comp)	Providence, KY	03/22/07	03/21/07
61167	Photronics Inc (Comp)	Allen, TX	03/22/07	03/13/07
61168	CECO—Commercial Enameling Company (State)	Huntington Park, CA	03/22/07	03/21/07
61169	Mitsui Components (USA) Inc (Comp)	Casa Grande, AZ	03/22/07	03/19/07
61170	Centurion Wireless Technologies d/b/a Laird Technologies (State).	Lincoln, NE	03/22/07	03/22/07
61171	Sandusky Atho International (Comp)	Butner, NC	03/23/07	03/22/07
61172	Keystone Weaving Mills Inc (Comp)	York, PA	03/23/07	03/16/07
61173	Viking Tool and Drill (State)	St Paul, MN	03/23/07	03/22/07
61174	Indian Tube Corporation (Comp)	Evansville, IN	03/23/07	03/02/07

[FR Doc. E7–6184 Filed 4–3–07; 8:45 am]
BILLING CODE 4510–FN–P

DEPARTMENT OF LABOR

Employment and Training Administration

[TA–W–59,189; TA–W–59,189A]

Photronics, Inc., Austin, TX; Including an Employee of Photronics, Inc., Austin, Texas; Located in Chandler, Arizona; Amended Certification Regarding Eligibility To Apply for Worker Adjustment Assistance and Alternative Trade Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273), and Section 246 of the Trade Act of 1974 (26 U.S.C. 2813), as amended, the Department of Labor issued a Certification Regarding Eligibility to Apply for Worker Adjustment Assistance and Alternative Trade Adjustment Assistance on May 9, 2006, applicable to workers of Photronics, Inc., Austin, Texas. The notice was published in the **Federal Register** on May 24, 2006 (71 FR 29983).

At the request of a State agency, the Department reviewed the certification for workers of the subject firm. New information shows that a worker separation has occurred involving an employee of the Austin, Texas facility of Photronics, Inc., located in Chandler, Arizona.

Mr. Karl White provided sales function services for the production of photomasks produced by the subject firm.

Based on these findings, the Department is amending this certification to include employees of the Austin, Texas facility of Photronics, Inc. located in Chandler, Arizona.

The intent of the Department's certification is to include all workers of Photronics, Inc., Austin, Texas who were adversely affected by a shift in production to Taiwan, Korea, China and the United Kingdom.

The amended notice applicable to TA–W–59,189 is hereby issued as follows:

All workers of Photronics, Inc., Austin, Texas (TA–W–59,189), and including an employee located in Chandler, Arizona (TA–W–59,189A), who became totally or partially separated from employment on or after March 31, 2005, through May 9, 2008, are eligible to apply for adjustment assistance under Section 223 of the Trade Act of 1974 and are also eligible to apply for alternative trade adjustment assistance under Section 246 of the Trade Act of 1974.

Signed at Washington, DC, this 26th day of March 2007.

Linda G. Poole,

Certifying Officer, Division of Trade Adjustment Assistance.

[FR Doc. E7–6183 Filed 4–3–07; 8:45 am]
BILLING CODE 4510–FN–P

DEPARTMENT OF LABOR

Employment and Training Administration

[TA–W–60,970]

TDS/US Automotive; Chesapeake, VA; Notice of Termination of Investigation

Pursuant to Section 221 of the Trade Act of 1974, as amended, an investigation was initiated on February 16, 2007 in response to a worker petition filed a company official on behalf of workers at TDS/US Automotive, Chesapeake, Virginia.

The petitioner has withdrawn the petition. Thus, this investigation is terminated.

Signed at Washington, DC, this 26th day of March 2007.

Richard Church,

Certifying Officer, Division of Trade Adjustment Assistance.

[FR Doc. E7–6182 Filed 4–3–07; 8:45 am]
BILLING CODE 4510–FN–P

SECURITIES AND EXCHANGE COMMISSION

Proposed Collection; Comment Request

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of Filings and Information Services, Washington, DC 20549.

Extension: Rule 31; SEC File No. 270–537; OMB Control No. 3235–0597.

Notice is hereby given that pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (''Commission'') is soliciting comments on the collection of information summarized below. The Commission plans to submit this existing collection of information to the Office of Management and Budget for extension and approval.

Section 31 (17 CFR 240.31) of the Securities Exchange Act of 1934 (15 U.S.C. 78ee) requires the Commission to collect fees and assessments from national securities exchanges and national securities associations (collectively, ''self-regulatory organizations'' or ''SROs'') based on the volume of their securities transactions. To collect the proper amounts, the Commission adopted Rule 31 and Form R31 under the Exchange Act whereby the SROs must report to the Commission the volume of their securities transaction and the Commission, based on that data, calculates the amount of fees and assessments that the SROs owe pursuant to Section 31. Rule 31 and Form R31 require the SROs to provide this data on a monthly basis.

The Commission estimates that each respondent makes approximately 12 such filings on an annual basis at an average hourly burden of approximately 1.6 hours per response. Currently, 15 respondents (14 national securities exchanges and one national securities association) are subject to the collection of information requirements of Rule 31. The Commission estimates that the total burden for all respondents is 288 hours (12 filings/respondent per year × 1.6 hours/filing × 15 respondents) 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 agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the proposed collection of information; (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 through the use of automated collection techniques or other forms of information technology. Consideration will be given to comments and suggestions submitted in writing within 60 days of this publication.

Comments regarding the above information should be directed to the following persons: (i) Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Office of Management and Budget, Room 10102, New Executive Office Building, Washington, DC 20503 or by sending an e-mail to: *David_Rostker@omb.eop.gov*; and (ii) R. Corey Booth, Director/Chief Information Officer, Securities and Exchange Commission, c/o Shirley Martinson, 6432 General Green Way, Alexandria, VA 22312 or by sending an e-mail to: *PRA_Mailbox@sec.gov*. Comments must be submitted to the Office of Management and Budget within 60 days of this notice.

Dated: March 26, 2007.

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E7–6218 Filed 4–3–07; 8:45 am]

BILLING CODE 8010–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–55547; File No. SR–Amex–2006–110]

Self-Regulatory Organizations; American Stock Exchange LLC; Order Granting Approval of Proposed Rule Change Relating to Options Based on Commodity Pool ETFs

March 28, 2007.

I. Introduction

On November 24, 2006, the American Stock Exchange LLC (''Amex'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission''), pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1] and Rule 19b–4 thereunder,[2] a proposal to amend certain rules to permit the listing and trading of options on securities issued by trust issued receipts (''Commodity TIRs''), partnership units, and other entities (referred herein to as ''Commodity Pool ETFs'') that hold or invest in commodity futures products. The proposed rule change was published for comment in the **Federal Register** on February 6, 2007.[3] The Commission received no comments regarding the proposal. This order approves the proposed rule change.

II. Description of the Proposal

The purpose of the proposed rule change is to enable the listing and trading on the Exchange of options on interests in Commodity Pool ETFs that trade directly or indirectly commodity futures products. As a result, Commodity Pool ETFs are subject to the Commodity Exchange Act (''CEA'') due to their status as a commodity pool,[4] and therefore, regulated by the Commodity Futures Trading Commission (''CFTC'').[5] Commodity Pool ETFs may hold or trade in one or more types of investments that may include any combination of securities, commodity futures contracts, options on commodity futures contracts, swaps, and forward contracts.

Currently, Commentary .06 to Amex Rule 915 provides securities deemed appropriate for options trading shall include shares or other securities (''Exchange-Traded Fund Shares'') that are principally traded on a national securities exchange or through the facilities of a national securities association and reported as an NMS security, and that: (i) Represent an interest in a registered investment company organized as an open-end management investment company, a unit investment trust or a similar entity which holds securities constituting or otherwise based on or representing an investment in an index or portfolio of securities; or (ii) represent interest in a trust or other similar entity that holds a specified non-U.S. currency deposited with the trust or similar entity when aggregated in some specified minimum number may be surrendered to the trust by the beneficial owner to receive the specified non-U.S. currency and pays the beneficial owner interest and other distributions on the deposited non-U.S. currency, if any, declared and paid by the trust.

The proposal would amend Commentary .06 to Rule 915 to expand the type of options to include the listing and trading of options based on shares of Commodity Pool ETFs (the ''Shares'') that may hold or invest directly or indirectly in commodity futures products, including but not limited to, commodity futures contracts, options on commodity futures contracts, swaps, and forward contracts. For Commodity Pool ETFs, a comprehensive surveillance sharing agreement will be required between the Exchange and the marketplace or marketplaces with last sale reporting that represent(s) the highest volume in such commodity futures contracts and/or options on commodity futures contracts on the specified commodities or non-U.S. currency, which are utilized by the national securities exchange where the underlying Commodity Pool ETFs are listed and traded.[6] The Exchange has represented that it has an adequate surveillance program in place for options based on Commodity Pool ETFs.

Under the applicable continued listing criteria in Commentary .07 to Amex Rule 916, the options on the Shares shall not be deemed to meet the Exchange's requirements for continued approval, and the Exchange shall not open for trading any additional series of option contracts of the class covering the Shares whenever the Shares are subject to delisting as follows: (1) Following the initial twelve-month period beginning upon the commencement of trading of the Shares, there are fewer than 50 record and/or beneficial holders of the Shares for 30 or more consecutive trading days; (2) the value of the index, non-U.S. currency, portfolio of commodities including commodity futures contracts, options on commodity futures contracts, swaps, forward contracts and/or options on physical commodities, or portfolio of securities on which the Shares are based is no longer calculated or available; or (3) such other event occurs or condition exists that in the opinion of the Exchange makes further dealing on the Exchange inadvisable. Additionally, the options on the Shares shall not be deemed to meet the requirements for continued approval, and the Exchange shall not open for trading any additional series of option contracts of the class covering such Shares, if the Shares are halted from trading on their primary market, or if the Shares are delisted, or the value of the index or portfolio on which the Shares are based is no longer calculated or available.

The proposal would amend Amex Rule 3 to require members to establish, maintain, and enforce written policies and procedures to prevent the misuse of material nonpublic information it might have or receive in a related security, option or derivative or in the applicable related commodity, commodity futures or options on commodity futures, or any other related commodity derivatives. The proposal would also amend Amex Rule 957 to ensure that the specialist and Registered Traders handling the Shares provide the Exchange with all necessary information relating to their trading in the applicable, physical commodities, physical commodity options, commodity futures contracts, options on commodity futures contracts, any other derivatives based on such commodity. Lastly, the revision to Rule 957 would prohibit a specialist or Registered Trader engaging in physical commodities, physical commodity options, commodity futures contracts, options on commodity futures contracts, any other derivatives based on such commodity from trading in an account

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 55187 (January 29, 2007), 72 FR 5467.

[4] A ''commodity pool'' is defined in CFTC Regulation 4.10(d)(1) as any investment trust, syndicate, or similar form of enterprise operated for the purpose of trading commodity interests. CFTC regulations further provide that a ''commodity interest'' means a commodity futures contract and any contract, agreement or transaction subject to Commission regulation under section 4c or 19 of the Act. *See* CFTC Regulation 4.10(a).

[5] The manager or operator of a ''commodity pool'' is required to register, unless applicable exclusions apply, as a commodity pool operator (''CPO'') and commodity trading advisor (''CTA'') with the CFTC and become a member of the National Futures Association (''NFA'').

[6] *See* proposed Commentary .06(a)(v) to Amex Rule 915.

which has not been reported to the Exchange.

III. Discussion

After careful consideration, the Commission finds that the proposed rule change is consistent with the requirements of the Act and the rules and regulations thereunder applicable to a national securities exchange[7] and, in particular, the requirements of Section 6 of the Act.[8] Specifically, the Commission finds that the proposed rule change is consistent with Section 6(b)(5) of the Act,[9] which requires, among other things, that the rules of a national securities exchange be designed 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.

Surveillance

The Commission notes that the Exchange has represented that it has an adequate surveillance program in place for options based on Commodity Pool ETFs. The Exchange may obtain trading information via the Intermarket Surveillance Group (''ISG'') from other exchanges who are members or affiliates of the ISG and have entered into numerous comprehensive surveillance sharing agreements with various commodity futures exchanges worldwide. Prior to listing and trading options on Commodity Pool ETFs, the Exchange represented that it will either have the ability to obtain specific trading information via ISG or through a comprehensive surveillance sharing agreement with the exchange or exchanges where the particular commodity futures and/or options on commodity futures are traded. In addition, the Exchange represented that the addition of Commodity Pool ETF options will not have any effect on the rules pertaining to position and exercise limits[10] or margin.[11]

Listing and Trading of Options on Commodity Pool ETFs

The Commission notes that, pursuant to the proposed rule change, a Commodity Pool ETF will be subject to the provisions of Amex Rules 915 and 916, as applicable. These provisions include requirements regarding initial and continued listing standards, the creation/redemption process for ETFs, and trading halts. All Commodity Pool ETFs must be traded through a national securities exchange or through the facilities of a national securities association, and must be ''NMS stock'' as defined under Rule 600 of Regulation NMS.[12]

The Commission believes that this proposal is necessary to enable the Exchange to list and trade options on an expanding range of Commodity Pool ETFs currently approved for trading and that it is reasonable to expect other types of Commodity Pool ETFs to be introduced for trading in the future. This proposal would help ensure that the Exchange will be able to list options on Commodity Pool ETFs that have been recently launched as well as any other similar Commodity Pool ETFs that may be listed and traded in the future[13] thereby offering investors greater option choices.

IV. Conclusion

It is therefore ordered, pursuant to Section 19(b)(2) of the Act,[14] that the proposed rule change (SR–Amex–2006–110), is hereby approved.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[15]

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E7–6200 Filed 4–3–07; 8:45 am]

BILLING CODE 8010–01–P

[7] In approving this proposed rule change, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

[8] 15 U.S.C. 78f.

[9] 15 U.S.C. 78f(b)(5).

[10] *See* Amex Rules 904 and 905.

[11] *See* Amex Rule 462.

[12] 17 CFR 242.600(b)(47).

[13] 17 CFR 240.19b–4(e).

[14] 15 U.S.C. 78s(b)(2).

[15] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–55550; File No. SR–NASDAQ–2007–010)

Self-Regulatory Organizations; The NASDAQ Stock Market LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change and Amendment No. 2 Thereto To Amend Rule 4611 Relating to Sponsored Access

March 28, 2007.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on February 16, 2007, The NASDAQ Stock Market LLC (''Nasdaq'' or ''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 substantially prepared by Nasdaq. On February 23, 2007, Nasdaq filed Amendment No. 1 to the proposed rule change but subsequently withdrew it. On February 23, 2007, Nasdaq filed Amendment No. 2 to the proposed rule change. The Exchange has filed the proposal as a ''non-controversial'' rule change pursuant to Section 19(b)(3)(A) of the Act[3] and Rule 19b–4(f)(6) thereunder,[4] which renders it effective upon filing with the Commission. The Commission is publishing this notice to solicit comments on the proposed rule change, as amended, from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

Nasdaq proposes to amend the Nasdaq Rule 4611 to update and codify the requirements applicable to Nasdaq members that provide sponsored access to other firms and customers to the Nasdaq execution system. The text of the proposed rule change is available at Nasdaq, the Commission's Public Reference Room, and *http://www.nasdaq.com*.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, Nasdaq included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. Nasdaq has prepared summaries, set forth in Sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

Nasdaq proposes to amend the Nasdaq Rule 4611 to update and codify the requirements applicable to Nasdaq members that provide sponsored access to other firms and customers to the Nasdaq execution system. Currently, Nasdaq members provide sponsored access consistent with guidance set forth in NASD Notice to Members 98–66 as updated by the NASD in Notice

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A).

[4] 17 CFR 240.19b–4(f)(6).

to Members 04–66.[5] Consistent with its status as an independent self-regulatory organization and the need to establish rules governing the use of its systems, Nasdaq proposes to adopt a sponsored access rule in the Nasdaq Rule Manual.

In recognition of the fact that Nasdaq members are members of other exchanges, that they use other exchanges' systems, and that they provide or receive sponsored access on other exchanges in the same manner as on Nasdaq, Nasdaq is proposing to adopt a sponsored access rule that is identical to that of another exchange, specifically NYSE Arca, Inc. (''NYSE Arca''). The NYSE Arca sponsored access rule has, by virtue of Commission approval, been determined to be consistent with the Act, including being consistent with the public interest and the protection of investors.

The proper usage of Nasdaq's systems and the protection of investors will be achieved in several ways. Sponsored participants must enter into and maintain customer agreements with one or more sponsoring members, establishing proper relationships and accounts through which the sponsored participant may trade on the Nasdaq Market Center. In such customer agreements sponsored participant and its sponsoring member must agree in writing to ''Sponsorship Provisions'' that (1) obligates the sponsoring member and sponsored participant to enter into a contractual relationship with Nasdaq; (2) ensures that orders and trades are honored; (3) holds the sponsoring member responsible for the conduct of sponsored participants; (4) obligates sponsored participants to comply with all applicable Nasdaq rules; (5) restricts access to Nasdaq systems to a limited group of known and educated users, (6) requires sponsoring members to have procedures to monitor its employees, agents, and customers in their access to and use of Nasdaq systems; and (7) ensures full payment of all applicable Nasdaq fees.

The proposed rule change is intended to codify practices currently in use in existing sponsored access relationships.

2. Statutory Basis

Nasdaq believes that the proposed rule change is consistent with the provisions of Section 6 of the Act,[6] in general, and with Section 6(b)(5) of the Act,[7] in particular, in that the proposal 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.

B. Self-Regulatory Organization's Statement on Burden on Competition

Nasdaq does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

Written comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing rule change does not: (1) Significantly affect the protection of investors or the public interest; (2) impose any significant burden on competition; and (3) become operative for 30 days after the date of this filing, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A) of the Act[8] and Rule 19b–4(f)(6) thereunder.[9]

A proposed rule change filed under 19b–4(f)(6) normally may not become operative prior to 30 days after the date of filing.[10] However, Rule 19b–4(f)(6)(iii)[11] permits the Commission to 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. The Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest because such waiver would permit Nasdaq to immediately implement the proposed rule change. For this reason, the Commission designates the proposed rule change to be operative upon filing with the Commission.[12]

At any time within 60 days of the filing of such proposed rule change the Commission may summarily abrogate 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.

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 (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov*. Please include File Number SR–NASDAQ–2007–010 on the subject line.

Paper Comments

- Send paper comments in triplicate to Nancy M. Morris, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NASDAQ–2007–010. This file number should be included on the subject line if e-mail 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 Web site (*http://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

[5] Nasdaq established Rule 4611(d) in order to codify the requirements set forth in the aforementioned NASD Notices to Members. *See* Securities Exchange Act Release No. 55061 (January 8, 2007), 72 FR 2052 (January 17, 2007) (SR–NASDAQ–2006–061). Nasdaq is amending Rule 4611(d) in order to match the regulatory requirements imposed by another exchange and, thereby, to promote uniform regulation of sponsored access relationships.

[6] 15 U.S.C. 78f.

[7] 15 U.S.C. 78f(b)(5).

[8] 15 U.S.C. 78s(b)(3)(A).

[9] 17 CFR 240.19b–4(f)(6).

[10] 17 CFR 240.19b–4(f)(6)(iii). In addition, Rule 19b–4(f)(6)(iii) requires that a self-regulatory organization submit to 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. Nasdaq has satisfied the five-day pre-filing notice requirement.

[11] *Id.*

[12] For the purposes only of waiving the 30-day operative delay, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room. Copies of the filing also will be available for inspection and copying at the principal office of Nasdaq. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NASDAQ–2007–010 and should be submitted on or before April 25, 2007.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[13]

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E7–6179 Filed 4–3–07; 8:45 am]

BILLING CODE 8010–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–55563; File No. SR–NASDAQ–2007–031]

Self-Regulatory Organizations; The NASDAQ Stock Market LLC; Notice of Filing of Proposed Rule Change Relating to Trading Three-Character Symbols

March 30, 2007.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on March 29, 2007, The NASDAQ Stock Market LLC (''Nasdaq'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been substantially prepared by Nasdaq. 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 the Substance of the Proposed Rule Change

Nasdaq proposes to allow any company with a three-character symbol that transfers its securities to Nasdaq from another domestic market to continue using the existing three-character symbol that identifies the company's securities.

[13] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, Nasdaq included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. Nasdaq has prepared summaries, set forth in Sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

Historically, securities listed on Nasdaq have traded using four or five character symbols.[3] In 2005, however, Nasdaq announced its intent to allow companies listed on Nasdaq to also use one-, two-, or three-character symbols beginning on January 31, 2007.[4] This announcement was designed to provide market participants and vendors the time needed to make required changes to their own systems that may be affected by the change. Nasdaq announced a series of dates throughout December 2006 and January and February 2007 where market participants could test trading Nasdaq stocks using one-, two-, or three-character symbols on weekends, in after hour sessions, and during full day sessions.[5] Beginning February 20, 2007, Nasdaq had the ability to accept and distribute Nasdaq-listed securities with one-, two-, or three-character symbols. Nasdaq reminded market participants about this change again on March 1, 2007, stressing that ''[a]ll customers should have completed their coding and testing efforts to ensure their readiness to support 1-, 2- and 3-character NASDAQ-listed issues.'' [6] On March 22, 2007, Delta Financial Corporation transferred the listing of its common stock to Nasdaq from the American Stock Exchange (''Amex'') and maintained its three-character symbol, DFC.[7] Nasdaq represents that there have been no trading problems reported to Nasdaq as a result of trading that security on Nasdaq with a three-character symbol.

Nasdaq now proposes to allow any company with a three-character symbol that transfers its securities to Nasdaq from another domestic market to continue using the existing three-character symbol that identifies the company's securities.[8] Nasdaq believes that this will promote competition among exchanges and reduce investor confusion. Specifically, Nasdaq believes that issuers should have the freedom of choice and competition. Nasdaq believes that as issuers face the important choice of where to list their equities, the symbol an issuer currently uses should not factor prominently in the listing decision process. Similarly, Nasdaq believes that the symbol that a market assigns to an issuer should not serve as an anchor if the issuer wishes to transfer to a competing market. Nasdaq believes that, as such, permitting the portability of these symbols will enhance competition among exchanges and encourage issuers to evaluate exchanges on the basis of objective criteria, including the most efficient trading platform for investors and the lowest costs for shareholders.

Nasdaq believes that permitting companies to continue to use their historical symbol will also reduce investor confusion associated with any such transfer because investors will continue to be able to obtain quotations and execute trades using the same familiar symbol and will allow the issuer to maintain a symbol that has

[3] This includes securities listed on Nasdaq's predecessor market, operated as a facility of the NASD.

[4] *See* Head Trader Alert 2005–133 (November 14, 2005), available at: *http://www.nasdaqtrader.com/Trader/News/2005/headtraderalerts/hta2005-133.stm* and Vendor Alert 2005–070 (November 14, 2005), available at: *http://www.nasdaqtrader.com/Trader/News/2005/vendoralerts/nva2005-070.stm.* See also Head Trader Alert 2006–144 (September 29, 2006), available at: *http://www.nasdaqtrader.com/Trader/News/2006/headtraderalerts/hta2006-144.stm,* Head Trader Alert 2006–193 (November 16, 2006), available at: *http://www.nasdaqtrader.com/Trader/News/2006/headtraderalerts/hta2006-193.stm* and Vendor Alert 2006–065 (October 4, 2006), available at: *http://www.nasdaqtrader.com/Trader/News/2006/vendoralerts/nva2006-065.stm.*

[5] *See* Head Trader Alert 2006-201 (December 6, 2006), available at: *http://www.nasdaqtrader.com/Trader/News/2006/headtraderalerts/hta2006-201.stm,* Head Trader Alert 2007–008 (January 25, 2007), available at: *http://www.nasdaqtrader.com/Trader/News/2007/headtraderalerts/hta2007-008.stm,* Head Trader Alert 2007–011 (January 30, 2007), available at: *http://www.nasdaqtrader.com/Trader/News/2007/headtraderalerts/hta2007-011.stm,* Head Trader Alert 2007–020 (February 7, 2007), available at: *http://www.nasdaqtrader.com/Trader/News/2007/headtraderalerts/hta2007-020.stm,* and Head Trader Alert 2007–034 (February 16, 2007), available at: *http://www.nasdaqtrader.com/Trader/News/2007/headtraderalerts/hta2007-034.stm.*

[6] Head Trader Alert 2007–050 (March 1, 2007), available at: *http://www.nasdaqtrader.com/Trader/News/2007/headtraderalerts/hta2007-050.stm.*

[7] *See* Securities Exchange Act Release No. 55519 (March 26, 2007) (SR–NASDAQ–2007–025).

[8] Nasdaq states that it remains committed to working with the Commission and other markets to establish an equitable and transparent symbol assignment plan.

become a part of its identity to investors.[9]

Nasdaq believes that this proposal is also consistent with the historical practice of companies that have switched among national securities exchanges. Since August 2001, approximately 200 issues have transferred their listing between the Amex, the New York Stock Exchange (''NYSE''), and NYSE Arca, while maintaining their original ticker symbol upon transfer.[10] Now that Nasdaq is also a national securities exchange,[11] allowing companies to maintain their symbol when transferring to Nasdaq would be consistent with the current practices of other exchanges.

Finally, Nasdaq believes that the changes to its systems to accommodate one-, two-, and three-character symbols will enhance the strength of the U.S. capital markets. As a result of these technological changes, all Nasdaq systems, including the Securities Information Processor (SIP), are able to support all NYSE- and Amex-listed securities using their original symbols over its core transaction and data platforms. Nasdaq notes that this provides an added level of redundancy and resiliency for the U.S. capital markets, and is key to Nasdaq's ability to provide a full back-up for other equity markets in the event of a national or local emergency thereby enhancing the strength of the U.S. capital markets.

2. Statutory Basis

Nasdaq believes that the proposed rule change is consistent with the provisions of Section 6 of the Act,[12] in general and with Section 6(b)(5) of the Act,[13] in particular, in that it is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to remove impediments to a free and open market and a national market system, and, in general, to protect investors and the public interest. Nasdaq believes that the proposal will reduce investor confusion and encourage competition among exchanges.

B. Self-Regulatory Organization's Statement on Burden on Competition

Nasdaq does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act, as amended.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 35 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 self-regulatory organization consents, the Commission will:

(A) By order approve such proposed rule change, or

(B) Institute proceedings to determine whether the proposed rule change 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 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 (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov*. Please include File Number SR–NASDAQ–2007–031 on the subject line.

Paper Comments

- Send paper comments in triplicate to Nancy M. Morris, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NASDAQ–2007–031. This file number should be included on the subject line if e-mail 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 Web site (*http://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 inspection and copying in the Commission's Public Reference Room. Copies of such filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NASDAQ–2007–031 and should be submitted on or before April 25, 2007.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[14]

Florence E. Harmon,

Deputy Secretary.

[FR Doc. E7–6335 Filed 4–3–07; 8:45 am]

BILLING CODE 8010–01–P

[9] Nasdaq states that a market transfer will be transparent to investors because, under the Commission's rules, a company must announce the transfer of its listing on a Form 8–K. *See* Form 8–K, item 3.01(d). In addition, the issuer must publish notice of its intent to delist its securities from the current market, in a press release and on its Web site. *See* 17 CFR 240.12d2–2(c)(2)(iii).

[10] *See, e.g.*, Allis-Chambers Energy (announced on March 7, 2007 its intent to switch from Amex to NYSE keeping the symbol ALY), Yamana Gold Inc. (announced on December 21, 2006 its intent to switch from Amex to NYSE keeping the symbol AUY), VAALCO Energy (announced on October 2, 2006 its intent to switch from Amex to NYSE keeping the symbol EGY), the transfer of 15 iShares ETFs from the Amex to NYSE Arca keeping their symbols announced on September 27, 2006, and the transfer of The Latin America Equity Fund, Inc., Credit Suisse Asset Management Income Fund, Inc., The Chile Fund, among others, from NYSE to AMEX on May 11, 2006 keeping their respective symbols CIK, LAQ and CH. A complete list of these transfers is available from Nasdaq upon request.

[11] Nasdaq became operational as an exchange for Nasdaq-listed securities on August 1, 2006. See Nasdaq Issuer Alert 2006–001, available at: *http://www.complinet.com/file_store/pdf/rulebooks/nasdaq_ia2006-001.pdf. See also* Securities Exchange Act Release No. 53128 (January 13, 2006), 71 FR 3550 (January 23, 2006).

[12] 15 U.S.C. 78f.

[13] 15 U.S.C. 78f(b)(5).

[14] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–55548; File No. SR–NYSE–2006–71]

Self-Regulatory Organizations; New York Stock Exchange LLC; Order Granting Accelerated Approval of Proposed Rule Change as Modified by Amendment No. 1 To List and Trade Nine Series of Exchange-Traded Notes of Barclays Bank PLC Linked to the Performance of Sub-Indices of the Dow Jones—AIG Commodity Index SM

March 28, 2007.

On August 24, 2006, the New York Stock Exchange LLC (''Exchange'' or

''NYSE'') filed with the Securities and Exchange Commission (''Commission''), pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1] and Rule 19b–4 thereunder,[2] a proposed rule change to list and trade notes linked to the performance of sub-indices of the Dow Jones—AIG Commodity Index℠. On February 20, 2007, the Exchange submitted Amendment No. 1.[3] The proposed rule change was published for comment in the **Federal Register** on March 2, 2007.[4] The Commission received no comments on the proposal. This order approves the proposed rule change, as modified by Amendment No. 1, on an accelerated basis.

Under Section 703.19 of NYSE's Listed Company Manual (the ''Manual''),[5] the Exchange proposes to list and trade nine series of notes (''Notes'') issued by Barclays Bank PLC (''Barclays'' or ''Issuer''), which are linked to the performance of the following sub-indices (each sub-index herein referred to as the ''Index'' with respect to the corresponding series of Notes) of the Dow Jones—AIG Commodity Index℠: the Dow Jones—AIG Petroleum Total Return Sub-Index℠; the Dow Jones—AIG Livestock Total Return Sub-Index℠; the Dow Jones—AIG Agriculture Total Return Sub-Index℠; the Dow Jones—AIG Grains Total Return Sub-Index℠; the Dow Jones—AIG Energy Total Return Sub-Index℠; the Dow Jones—AIG Precious Metals Total Return Sub-Index℠; the Dow Jones—AIG ExEnergy Total Return Sub-Index℠; the Dow Jones—AIG Industrial Metals Total Return Sub-Index℠; and the Dow Jones—AIG Softs Total Return Sub-Index℠. Barclays intends to issue the Notes under the name ''iPath℠ Exchange-Traded Notes.''

The Indexes

Each Index is comprised of constituents making up the Dow Jones—AIG Commodity Index℠, which the Commission has previously reviewed in connection with the listing of exchange-traded notes.[6] Each Index is comprised of commodity contracts relating to a specific industry or sector.[7] For example, the Dow Jones—AIG Petroleum Total Return Sub-Index℠ includes those contracts in the Dow Jones—AIG Commodity Index℠ that relate to petroleum-related commodities: crude oil, heating oil and unleaded gasoline. Each Index is determined annually by AIG–FP and calculated daily by Dow Jones. The weightings of each Index component are a function of their weighting in the Dow Jones—AIG Commodity Index℠, which, in turn, derives from liquidity and world production data.

Dow Jones disseminates the Index value of each sub-index every 15 seconds (assuming the Index value has changed within such 15 second interval) from 8 a.m. to 3 p.m. ET and publishes a daily Index value at approximately 4 p.m. ET on each day on which the Index is calculated. The sub-index values can still be retrieved after 3 p.m. until the end of the Exchange trading day but their values are generally static after 3 p.m., although they may change if settlement values for Index components become available after that time.

The Notes

The Notes will offer investors exposure to specific commodity sectors. The Notes are debt securities of Barclays with a term of 30 years that provide for a cash payment at maturity or upon earlier exchange at the holder's option, based on the performance of the relevant Index according to a formula set forth in the notice of NYSE's proposal.[8] Unlike traditional debt securities, the Notes would not have a minimum principal amount that would be repaid prior to or at maturity. Accordingly, the return could be less than the original issue price. Also, holders of the Notes will not receive any interest payments from the Notes. Prior to maturity, Notes may be redeemed in large aggregations as described further in the notice of NYSE's proposal.

Because the Notes will be debt securities of Barclays, the Notes are dependent upon its creditworthiness. This credit risk is addressed by the listing standards in § 703.19(1) of NYSE's Manual, which provide that a security may not be listed on the Exchange unless its issuer satisfies certain financial requirements.

Section 703.19(2) of NYSE's Manual requires a market value of $4 million for initial listing of debt securities. In addition, the Notes would have to comply with continued listing standards in Section 802.01D of NYSE's Manual. The Exchange would remove from listing any security where the public distribution or aggregate market value has fallen below the specified thresholds or become so reduced to make further dealings on the Exchange inadvisable, or where such other event shall occur or condition exists which in the opinion of the Exchange makes further dealings on the Exchange inadvisable.

Pricing Information

An intraday Indicative Value meant to approximate the intrinsic economic value of the Notes will be calculated and published via the facilities of the Consolidated Tape Association (''CTA'') every 15 seconds throughout the NYSE trading day on each day on which the Notes are traded on the Exchange. Additionally, Barclays or an affiliate will calculate and publish the closing Indicative Value of the Notes on each trading day at *http://www.ipathetn.com.* The last sale price of the Notes will also be disseminated over the consolidated tape, subject to a 20-minute delay.[9]

Trading Rules

The Notes will trade as equity securities, subject to NYSE rules governing, among other things, priority, parity, and precedence of orders; specialist responsibilities; margin;[10] and customer suitability requirements. The Notes will trade between the hours of 9:30 a.m. and 4 p.m. ET. The Exchange would halt trading in the Securities if the circuit breaker parameters of Exchange Rule 80B have been reached and may halt trading pursuant to Exchange Rule 123D

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] Amendment No. 1 replaced and superseded the Exchange's original filing in its entirety.

[4] *See* Securities Exchange Act Release No. 55352 (February 26, 2007), 72 FR 9599 (''Notice'').

[5] Section 703.19 of the Manual provides that the Exchange may approve for listing and trading securities not otherwise covered by the criteria of Sections 1 and 7 of the Manual, provided the issue is suited for auction market trading.

[6] *See* Securities Exchange Act Release No. 53876 (May 25, 2006), 71 FR 32158 (June 2, 2006) (SR–NYSE–2006–16). As set out in that filing, the Dow Jones—AIG Commodity Index℠ is designed to be a diversified benchmark for commodities as an asset class and reflects the returns that are potentially available through an unleveraged investment in the futures contracts on physical commodities comprising the Index plus the rate of interest that could be earned on cash collateral invested Treasury Bills. The Dow Jones—AIG Commodity Index℠ was developed by AIGI International Inc., each year is determined by AIG Financial Products Corp. (''AIG-FP''), and is calculated by Dow Jones. The relative weightings of each component commodity is determined annually according to liquidity and dollar adjusted production data in 2/3 and 1/3 shares, respectively.

[7] *See* Notice, *supra* note 4, 72 FR at 9602–9604.

[8] *See* Notice, *supra* note 4, 72 FR at 9601.

[9] As described in the notice of the NYSE's proposal, the Indicative Value will not reflect price changes to the price of an underlying commodity between the close of trading of the futures contract at the relevant futures exchange and the close of trading on the NYSE at 4 p.m. ET. While the market for futures trading for each of the Index commodities is open, the Indicative Value can be expected to closely approximate the redemption value of the Notes. However, during NYSE trading hours when the futures contracts have ceased trading, spreads and resulting premiums or discounts may widen, and therefore, increase the difference between the price of the Notes and their redemption value.

[10] *See* NYSE Rule 431.

pending the dissemination of material news with respect to the issuer. If the Index value or the Indicative Value is not being disseminated as required, the Exchange may halt trading during the day on which the interruption to the dissemination of the Index value or the Indicative Value first occurs. If the interruption to the dissemination of the Index value or the Indicative Value persists past the trading day in which it occurred, the Exchange will halt trading no later than the beginning of the trading day following the interruption.

Surveillance

The NYSE has represented that it would rely on its existing surveillance procedures governing equities, which it represented are adequate to monitor trading of the Notes. Through information sharing agreements and its membership in the Intermarket Surveillance Group, the Exchange stated that it has access to all relevant trading information in connection with commodity futures comprising each Index. Further, the Exchange stated that it currently has the authority under NYSE Rule 476 to request the Exchange specialist in the Notes to provide NYSE Regulation with information that the specialist uses in connection with pricing the Notes on the Exchange, including specialist proprietary or other information regarding securities, commodities, futures, options on futures or other derivative instruments. The Exchange believes it also has authority to request any other information from its members—including floor brokers, specialists and ''upstairs'' firms—to fulfill its regulatory obligations.

Suitability

Pursuant to Exchange Rule 405, the Exchange will impose a duty of due diligence on its members and member firms to learn the essential facts relating to every customer prior to trading the Notes.[11] With respect to suitability recommendations and risks, the Exchange will require members, member organizations and employees thereof recommending a transaction in the Notes: (1) To determine that such transaction is suitable for the customer, and (2) to have a reasonable basis for believing that the customer can evaluate the special characteristics of, and is able to bear the financial risks of, such transaction.

[11] NYSE Rule 405 requires that every member, member firm or member corporation use due diligence to learn the essential facts relative to every customer and to every order or account accepted.

Discussion and Commission Findings

After careful consideration, the Commission finds that the proposed rule change is consistent with the requirements of the Act and the rules and regulations thereunder applicable to a national securities exchange.[12] In particular the Commission finds that the proposed rule change is consistent with the requirements of Section 6(b)(5) of the Act,[13] which requires among other things, that the Exchange's rules be designed to promote just and equitable principles of trade, to facilitate 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. The Commission notes that it has previously approved the listing and trading of other index-linked securities that have a structure similar to the Notes.[14]

The Commission further believes that the proposal is consistent with Section 11A(a)(1)(C)(iii) of the Act,[15] which sets forth Congress' finding that it is in the public interest and appropriate for the protection of investors and the maintenance of fair and orderly markets to assure the availability to brokers, dealers, and investors of information with respect to quotations for and transactions in securities. Quotations for and last-sale information regarding the Notes will be disseminated through the facilities of the Consolidated Tape Association (''CTA''). The value of each Index is calculated and disseminated daily and, because the composition of each Index is public and pricing of the constituents is transparent, it may be verified by a number of independent sources. In addition, an intraday Indicative Value for each Note series will be available through the CTA. Furthermore, financial information regarding the Issuer is publicly available, allowing investors to evaluate the creditworthiness of the Issuer. The Commission also believes that sufficient venues exist for obtaining reliable information so that holders of the Notes can track the value of their investment. Accordingly, the Commission finds that NYSE's proposal is reasonably designed to promote transparency in the pricing of the Notes, and to prevent trading when a reasonable degree of transparency cannot be assured.

The proposal also appears reasonably designed to prevent conveyance of inside information from the Index Calculator to market participants who may trade the Notes.

In support of this proposal, the Exchange has made the following representations:

(1) NYSE has received a representation from AIG–FP, the Index Sponsor, that it will

(a) Implement and maintain procedures reasonably designed to prevent the use and dissemination by relevant employees of AIG–FP, in violation of applicable laws, rules and regulations, of material non-public information relating to changes in the composition or method of computation or calculation of the Index and (b) periodically check the application of such procedures as they relate to officers and directors of AIG–FP directly responsible for such changes.[16]

(2) NYSE will, prior to trading the Notes, distribute an information memorandum to the membership providing guidance with regard to member firm compliance responsibilities (including suitability recommendations) when handling transactions in the Notes and highlighting the special risks and characteristics of the Notes. In addition, during the initial distribution of the Notes and during any subsequent distribution of the Notes, NYSE member organizations will deliver a prospectus to investors purchasing Notes from distributors.

(3) NYSE will rely on its existing surveillance procedures governing equities with regard to surveillance of the Notes, which are adequate to properly monitor trading of the Notes

[12] In approving the rule, the Commission notes that it has considered the proposed rule's impact on efficiency, competition and capital formation. *See* 15 U.S.C. 78c(f).

[13] 15 U.S.C. 78f(b)(5).

[14] *See, e.g.*, Securities Exchange Act Release Nos. 54177 (July 19, 2006), 71 FR 54177 (July 27, 2006) (SR–NYSE–2006–19) (relating to the trading of the Index-Linked Securities of Barclays Bank PLC linked to the Performance of the Goldman Sachs Crude Oil Total Return Index™); 53876 (May 25, 2006), 71 FR 32158 (June 2, 2006) (SR–NYSE–2006–16) (relating to the trading of the Index-Linked Securities of Barclays Bank PLC linked to the performance of the Dow Jones—AIG Commodity Index Total Return); and 53849 (May 22, 2006), 71 FR 30706 (May 30, 2006) (SR–NYSE–2006–20) (relating to the trading of the Index-Linked Securities of Barclays Bank PLC linked to the performance of the GSCI® Total Return Index).

[15] 15 U.S.C. 78k–1(a)(1)(C)(iii).

[16] AIG–FP is a wholly-owned guaranteed subsidiary of American International Group, Inc. It is not a broker-dealer or futures commission merchant; however, AIG–FP may have such affiliates. The Exchange has stated that Dow Jones does not have any affiliates engaged in the securities or commodities trading businesses and, as such, Dow Jones does not believe that such firewall procedures are necessary in its case. Dow Jones and the Dow Jones—AIG Commodity Index℠ Oversight Committee will adopt and maintain policies that acknowledge their obligations with respect to material non-public information. *See supra* note 6, 71 FR at 32159–32160 nn.10,15.

and detect violations of Exchange rules, thereby deterring manipulation.

(4) With regard to the Index components, the Exchange can obtain market all relevant trading information, including customer identity information, with respect to transactions through agreements with futures exchanges and participation in the Intermarket Surveillance Group.

(5) NYSE prohibits the initial and/or continued listing of any security that is not in compliance with Rule 10A–3 under the Act.[17]

This order is conditioned on NYSE's adherence to these representations.

Under the proposal, the Exchange will delist any series of the Notes under the following circumstances:

(1) (a) If, following the initial twelve month period from the date of commencement of trading of the Notes, the Notes have more than 60 days remaining until maturity and there are fewer than 50 beneficial holders of the Notes for 30 or more consecutive trading days; (b) if fewer than 100,000 Notes remain issued and outstanding; or (c) if the market value of all outstanding Notes is less than $1,000,000.

(2) If the Index value ceases to be calculated or available during the time the Notes trade on the Exchange on at least a 15 second basis through one or more major market data vendors or the sponsors of the Index.

(3) If, during the time the Notes trade on the Exchange, the Indicative Value ceases to be available on a 15 second delayed basis.

In addition, NYSE has represented that it would delist the Notes (unless the Commission approved a proposed rule change submitted pursuant to Rule 19b–4 under the Act) if: (1) Dow Jones and AIG–FP substantially change either the Index component selection methodology or the weighting methodology; (2) a new component is added to the Index (or pricing information is used for a new or existing component) that constitutes more than 10% of the weight of the Index with whose principal trading market the Exchange does not have a comprehensive surveillance sharing agreement; or (3) a successor or substitute index is used in connection with the Notes. The Commission believes that each of these circumstances represents material changes to the characteristics of the Index described herein and on which the Commission is basing its findings. Under these circumstances, the Exchange could not rely on this approval to list and trade the Notes.

[17] *See* 17 CFR 240.10A–3.

Acceleration

The Commission finds good cause to approve the proposal, as amended, prior to the thirtieth day after the amended proposal was published for comment in the **Federal Register**. Accelerating approval of the proposal should benefit investors who desire to participate in the designated Indexes by expediting the listing and trading of the Notes by the Exchange. The Commission also notes that the proposal is similar to others previously approved by the Commission, and does not appear to raise any new regulatory issues. Thus, the Commission finds good cause, consistent with Section 19(b)(2) of the Act,[18] to grant accelerated approval of the proposed rule change, as amended.

It is therefore ordered, pursuant to Section 19(b)(2) of the Act, that the proposed rule change (SR–NYSE–2006–71), as modified by Amendment No. 1, be, and it hereby is, approved on an accelerated basis.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[19]

J. Lynn Taylor,

Assistant Secretary.

[FR Doc. E7–6189 Filed 4–3–07; 8:45 am]

BILLING CODE 8010–01–P

[18] 15 U.S.C. 78s(b)(2).

[19] 17 CFR 200.30–3(a)(12).

SMALL BUSINESS ADMINISTRATION

Data Collection Available for Public Comments and Recommendations

ACTION: Notice and request for comments.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, this notice announces the Small Business Administration's intentions to request approval on a new and/or currently approved information collection.

DATES: Submit comments on or before June 4, 2007.

ADDRESSES: Send all comments regarding whether this information collection is necessary for the proper performance of the function of the agency, whether the burden estimates are accurate, and if there are ways to minimize the estimated burden and enhance the quality of the collection, to Janet Tasker, Deputy Associate Administrator, Office of Capital Access, Small Business Administration, 409 3rd Street SW., 8th Floor, Washington, DC 20416

FOR FURTHER INFORMATION CONTACT: Janet Tasker, Tasker, Office of Capitol Access, 202–205–6657, *janet.tasker@sba.gov.* Curtis B. Rich, Management Analyst, 202–205–7030, *curtis.rich@sba.gov*.

SUPPLEMENTARY INFORMATION:

Title: ''Office of Capital Access Online Survey.''

Description of Respondents: Finance Lenders, International Finance Lenders, 7(a) Lenders and CDC's in the 504 program, Small Business Investment Companies, Surety Bond Guarantee Companies.

Form No: N/A.

Annual Responses: 23,396.

Annual Burden: 1,204.

Jacqueline White,

Chief, Administrative Information Branch.

[FR Doc. E7–6247 Filed 4–3–07; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #10830]

Florida Disaster #FL–00021 Declaration of Economic Injury

AGENCY: U.S. Small Business Administration.

ACTION: Notice.

SUMMARY: This is a notice of an Economic Injury Disaster Loan (EIDL) declaration for the State of Florida, dated 3/26/2007.

Incident: Fire.

Incident Period: 11/19/2006.

Effective Date: 3/26/2007.

EIDL Loan Application Deadline Date: 12/26/2007.

ADDRESSES: *Submit completed loan applications to:* U.S. Small Business Administration, Processing and Disbursement Center, 14925 Kingsport Road, Fort Worth, TX 76155.

FOR FURTHER INFORMATION CONTACT: A. Escobar, Office of Disaster Assistance, U.S. Small Business Administration, 409 3rd Street, SW., Suite 6050, Washington, DC 20416.

SUPPLEMENTARY INFORMATION: Notice is hereby given that as a result of the Administrator's EIDL declaration, applications for economic injury disaster loans may be filed at the address listed above or other locally announced locations.

The following areas have been determined to be adversely affected by the disaster:

Primary County: Miami-Dade.

Contiguous Counties: Florida: Broward, Collier, Monroe.

The Interest Rate is: 4.000.

The number assigned to this disaster for economic injury is 108300.

The State which received an EIDL Declaration # is Florida.

(Catalog of Federal Domestic Assistance Number 59002)

Steven C. Preston,

Administrator.

[FR Doc. E7–6244 Filed 4–3–07; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

Notice; Small Business Administration Interest Rates

The Small Business Administration publishes an interest rate called the optional ''peg'' rate (13 CFR 120.214) on a quarterly basis. This rate is a weighted average cost of money to the government for maturities similar to the average SBA direct loan. This rate may be used as a base rate for guaranteed fluctuating interest rate SBA loans. This rate will be 5.000 (5) percent for the April–June quarter of FY 2007.

Janet A. Tasker,

Acting Associate Administrator for Financial Assistance.

[FR Doc. E7–6242 Filed 4–3–07; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

Audit and Financial Management Advisory (AFMAC) Committee Meeeting

Pursuant to the Federal Advisory Committee Act, Appendix 2 of title 5, United States Code, Public Law 92–463, notice is hereby given that the U.S. Small Business Administration, Audit and Financial Management Advisory Committee (AFMAC) will host a federal public meeting on Wednesday, April 18, 2007 at 9 a.m. EST. The meeting will take place at the U.S. Small Business Administration, 409 3rd Street, SW., Investment Division Conference Room, 6th Floor, Washington, DC 20416.

The purpose of this meeting is to discuss the SBA's FY 2006 Audit Remediation, FY 2007 Financial Reporting, FY 2007 Credit Subsidy Modeling, A–123 Internal Control Program, Information System Security, Performance Management Framework, FY 2007 PAR Content and Production, and the FY 2007 Audit.

Anyone wishing to attend must contact Jennifer Main in writing or by fax. Jennifer Main, Chief Financial Officer, 409 3rd Street, SW., 6th Floor, Washington, DC 20416, *phone:* (202) 205–6449, *fax:* (202) 205–6969, *e-mail: Jennifer.main@sba.gov.*

Matthew Teague,

Committee Management Officer.

[FR Doc. E7–6245 Filed 4–3–07; 8:45 am]

BILLING CODE 8025–01–P

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

Aviation Proceedings, Agreements Filed the Week Ending March 23, 2007

The following Agreements were filed with the Department of Transportation under the Sections 412 and 414 of the Federal Aviation Act, as amended (49 U.S.C. 1383 and 1384) and procedures governing proceedings to enforce these provisions. Answers may be filed within 21 days after the filing of the application.

Docket Number: OST–2007–27664.
Date Filed: March 20, 2007.
Parties: Members of the International Air Transport Association.
Subject:
TC12 North Atlantic-Africa except between USA and Reunion Resolutions and Specified Fares Tables (Memo 0252).
Intended effective date: 1 May 2007.

Docket Number: OST–2007–27666.
Date Filed: March 20, 2007.
Parties: Members of the International Air Transport Association.
Subject:
TC12 Mid Atlantic-Africa Resolutions and Specified Fares Tables (Memo 0253).
Intended effective date: 1 May 2007.

Docket Number: OST–2007–27667.
Date Filed: March 20, 2007.
Parties: Members of the International Air Transport Association.
Subject:
TC12 South Atlantic-Africa Resolutions and Specified Fares Tables (Memo 0254).
Intended effective date: 1 May 2007.

Docket Number: OST–2007–27671.
Date Filed: March 20, 2007.
Parties: Members of the International Air Transport Association.
Subject:
TC2 Europe-Africa Resolutions and Specified Fares Tables (Memo 0246).
Intended effective date: 1 May 2007.

Docket Number: OST–2007–27673.
Date Filed: March 20, 2007.
Parties: Members of the International Air Transport Association.
Subject:
TC2 Middle East-Africa Resolutions and Specified Fares Tables (Memo 0153).
Intended effective date: 1 May 2007.

Docket Number: OST–2007–27674.
Date Filed: March 20, 2007.
Parties: Members of the International Air Transport Association.
Subject:
TC2 Within Africa Resolutions and Specified Fares Tables (Memo 0174).
Intended effective date: 1 May 2007.

Renee V. Wright,

Program Manager, Docket Operations, Federal Register Liaison.

[FR Doc. E7–6266 Filed 4–3–07; 8:45 am]

BILLING CODE 4910–9X–P

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

Notice of Applications for Certificates of Public Convenience and Necessity and Foreign Air Carrier Permits Filed Under Subpart B (Formerly Subpart Q) During the Week Ending March 23, 2007

The following Applications for Certificates of Public Convenience and Necessity and Foreign Air Carrier Permits were filed under Subpart B (formerly Subpart Q) of the Department of Transportation's Procedural Regulations (See 14 CFR 301.201 *et seq*).

The due date for Answers, Conforming Applications, or Motions to Modify Scope are set forth below for each application. Following the Answer period DOT may process the application by expedited procedures. Such procedures may consist of the adoption of a show-cause order, a tentative order, or in appropriate cases a final order without further proceedings.

Docket Number: OST–2007–27718.

Date Filed: March 22, 2007.

Due Date for Answers, Conforming Applications, or Motion to Modify Scope: April 12, 2007.

Description: Application of Insel Air International B.V. requesting an exemption and a foreign air carrier permit authorizing it to engage in scheduled foreign air transportation of persons, property and mail between a point or points in Netherlands Antilles, on the one hand, and a point or points in the United States, on the other hand, via intermediate points.

Renee V. Wright,

Program Manager, Docket Operations, Federal Register Liaison.

[FR Doc. E7–6271 Filed 4–3–07; 8:45 am]

BILLING CODE 4910–9X–P

DEPARTMENT OF TRANSPORTATION

Federal Transit Administration

Public Transportation on Indian Reservations Program; Tribal Transit Program

AGENCY: Federal Transit Administration (FTA), DOT.

ACTION: Notice of Funding Availability: Solicitation of Grant Applications for FY 2007 Tribal Transit Program Funds.

SUMMARY: This notice announces the availability of Fiscal Year (FY) 2007 funds for the Public Transportation on Indian Reservations Program, a program authorized by the Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA–LU). This notice also announces a national solicitation for Grant Applications for FY 2007 Tribal Transit Program (TTP) funds to be selected on a competitive basis; the grant terms and conditions that apply to this program; and grant application procedures and selection criteria for FY 2007 projects.

ADDRESSES: This announcement is available on the Federal Transit Administration (FTA) Web site at *http://www.fta.dot.gov*. FTA will announce final selections on the Web site and in the **Federal Register**. FTA will post a synopsis of this announcement on the government-wide electronic grants Web site at: *http://www.grants.gov*. Applicants may submit applications in one of three ways: electronically through Grants.gov, delivery in hard copy to Federal Transit Administration, 1200 New Jersey Avenue, SE., Washington, DC, *Attention:* Lorna R. Wilson; or sending by e-mail to *fta.tribalprogram@dot.gov*.

DATES: Applicants must submit completed applications for Public Transportation on Indian Reservations Program grants in hard copy to the FTA, via e-mail August 2, 2007, or electronically through the Grants.gov Web site by the same date. Anyone intending to apply electronically should initiate the process of registering on the grants.gov site immediately to ensure completion of registration before the deadline for submission. FTA will announce grant selections in the **Federal Register** when the competitive selection process is complete.

Applicants should be aware that materials sent through the U.S. Postal Service are subject to significant delays in delivery due to the security screening process. Use of courier or express delivery services is recommended.

FOR FURTHER INFORMATION CONTACT: Contact the appropriate FTA regional Tribal Liaison (Appendix A) for application-specific information and issues. For general program information, contact Lorna R. Wilson, Office of Transit Programs, at (202) 366–2053, e-mail: *Lorna.Wilson@dot.gov*. A TDD is available at 1–800–877–8339 (TDD/FIRS).

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I. Overview

Section 3013 of SAFETEA–LU, [Pub. L. 109–59 (August 15, 2005)] amended 49 U.S.C. 5311(c) by establishing the Public Transportation on Indian Reservations Program (Tribal Transit Program). This program authorizes direct grants ''under such terms and conditions as may be established by the Secretary'' to Indian tribes for any purpose eligible under FTA's Nonurbanized Area Formula Program, 49 U.S.C. 5311. The funding for the TTP will increase from $8 million in FY 2006 to $15 million in FY 2009. The Conference Report to SAFETEA–LU indicated that the funds set aside for Indian tribes in the TTP are not meant to replace or reduce funds that Indian tribes receive from States through FTA's Nonurbanized Area Formula Program. The Catalog of Federal Domestic Assistance (CFDA) number for the program is 20.509.

II. Background

On August 15, 2006, FTA published a **Federal Register** Notice of Funding Availability: Solicitation of Grant Applications for FY 2006 TTP Funds (71 FR 46878). This notice accomplished several purposes. First, the notice responded to written comments FTA received in response to an earlier **Federal Register** notice dated March 22, 2006, (71 FR 14618) ''Public Transportation on Indian Reservations Program (49 U.S.C. 5311(c)(1)): Notice of Public Meetings, Proposed Grant Program Provisions,'' and responded to oral comments FTA received during two announced public meetings that were held on April 4, 2006, in Denver, Colorado, and on April 7, 2006, in Kansas City, Missouri. Second, the notice announced the availability of funds in FY 2006 for the TTP. Third, the notice announced a national solicitation for Grant Applications for FY 2006 TTP funds to be selected on a competitive basis; the grant terms and conditions that apply to this new program; and grant application procedures and selection criteria for FY 2006 projects. Projects selected for funding under that Notice are published elsewhere in today's issue of the **Federal Register**.

III. Funding Opportunity Description

A. Authorized Funding for FY 2007

Section 3013 of SAFETEA–LU established the TTP under 49 U.S.C. 5311(c). Section 5311(c) also authorized $45 million from the Nonurbanized Area Formula Grants Program (49 U.S.C. 5311) for FY 2006–2009, to be apportioned for grants directly to Indian tribes. Under the TTP, Indian tribes are eligible direct recipients. The funds are to be apportioned for grants to Indian tribes for any purpose eligible under the Nonurbanized Area Formula Program (Section 5311 program). In FY 2007, $10 million is available for allocation to projects selected through the process announced in this notice.

B. Background

Prior to SAFETEA–LU, the Section 5311 program did not include a separate

public transit program for tribes. Tribes were eligible under the Section 5311 program only as subrecipients. SAFETEA–LU authorized a TTP and authorized tribes to be direct recipients of Section 5311 Program funds. As expressed in the Conference Report (H. Conf. Rpt. 109, 203 at 943) for SAFETEA–LU, Congress intended that the funds available for the TTP not replace or reduce funds tribes receive from States under the Section 5311 program.

IV. Award Information

The number and size of awards will be determined by a competitive process. However, funding is available for start up services, enhancements or expansion of existing transit services, and for planning studies and operational planning. Planning grants will be limited to $25,000 in FY 2007 funds per applicant. Tribes may apply for multiple year projects, but given the demand for the funding, it is likely that only one year will be considered for FY 2007 funding. Priority for FY 2007 funding will be given to continuation funding for start-up projects selected in FY 2006. All tribes seeking FY 2007 funds must submit a grant application to FTA by the deadline indicated above. However, tribes applying for continuation funding may incorporate by reference materials or information previously submitted to FTA as part of their application for FY 2006 funding.

V. Eligibility Information

A. Eligible Applicants

Eligible direct recipients include Federally-recognized Indian tribes or Alaska Native villages, groups, or communities as identified by the Bureau of Indian Affairs (BIA) in the U.S. Department of the Interior. To be eligible recipients, tribes must have the requisite legal, financial and technical capabilities to receive and administer Federal funds under this program.

B. Eligible Projects

Eligible recipients may use TTP funds for any purpose authorized under the Section 5311 program. This means that grants can be awarded to recipients located in rural and small urban areas with populations under 50,000 not identified as an urbanized area by the Bureau of the Census for public transportation capital projects, operating costs of equipment and facilities for use in public transportation, planning, and the acquisition of public transportation services, including service agreements with private providers of public transportation services. Service funded under this program must be designed to be accessible to members of the general public who have disabilities. Coordinated human service transportation that primarily serves elderly persons and persons with disabilities, but that is not restricted from carrying other members of the public, is considered available to the general public if it is marketed as public transportation.

VI. Cost Sharing or Matching

No cost sharing is required for this program. However, FTA encourages tribes to leverage the program funds and demonstrate commitment to the project through in-kind contributions and use of other funding sources that are available to support public transportation service.

VII. Terms and Conditions

Section 3013 of SAFETEA–LU amended 49 U.S.C. 5311(c) by authorizing funds for the TTP ''under such terms and conditions as may be established by the Secretary.'' Pursuant to this discretionary statutory authority in Section 5311(c), FTA published a **Federal Register** notice dated March 22, 2006 (71 FR 14618), ''Public Transportation on Indian Reservations Program (49 U.S.C. 5311(c)(1)): Notice of Public Meetings, Proposed Grant Program Provisions,'' and proposed certain statutory and regulatory terms and conditions that should apply to grants awarded under the TTP. The statutory and regulatory terms and conditions pertained only to U.S. Department of Transportation and FTA requirements. As FTA indicated its March 22, 2006 **Federal Register** notice (71 FR 14618), FTA does not possess the requisite authority to waive cross-cutting or government-wide statutory and regulatory requirements (e.g., National Environmental Policy Act requirements). However, to the extent permitted by law, and in recognition of the unique status and autonomy of Indian tribal governments, FTA has made every effort to establish terms and conditions that balance the objective of the TTP, which will directly benefit transit projects for Indian tribes, with other national objectives (e.g., safety) that are important not only to Indian tribes, but also to the general public.

FTA received a substantial number of comments from Indian tribes and other groups concerning certain proposed terms and conditions for the TTP. FTA addressed these comments in the **Federal Register** Notice dated August 15, 2006, (71 FR 46878) and established appropriate grant requirements for the TTP.

The following terms and conditions apply to the TTP:

1. Common Grant Rule (49 CFR part 18), ''Uniform Administrative Requirements for Grants and Cooperative Agreements to State and Local Governments.'' This is a government-wide requirement that applies to all Federal assistance programs.

2. Civil Rights Act of 1964, as amended (42 U.S.C. 2000d). Unless Indian tribes are specifically exempted from civil rights statutes, compliance with civil rights statutes is being required, including compliance with equity in service. However, Indian tribes will not be required to comply with FTA program-specific guidance for Title VI and Title VII.

3. Section 504 of the Rehabilitation Act of 1973, as amended (29 U.S.C. 794 *et seq.*), and the Americans with Disabilities Act (ADA) requirements in 49 CFR parts 27, 37, and 38. These are government-wide requirements that apply to all Federal programs.

4. Drug and Alcohol Testing requirements (49 CFR part 655). FTA will apply this requirement because it addresses a national safety issue for operators of public transportation.

5. National Environmental Policy Act, as amended (42 U.S.C. 4321 *et seq*). This is a government-wide requirement that applies to all Federal programs.

6. Charter Service and School Bus transportation requirements in 49 CFR parts 604 and 605. The definition of ''public transportation'' in 49 U.S.C. 5302(a)(10) specifically excludes school bus and charter service.

7. National Transit Database (NTD) Reporting requirement. Title 49 U.S.C. 5335 requires NTD reporting for recipients of Section 5311 funds. The TTP is a Section 5311 program that will provide funds directly to Indian tribes. Therefore, this reporting requirement applies.

8. Bus Testing requirements (49 CFR part 665). To ensure that vehicles acquired under this program will meet adequate safety and operational standards, this requirement will apply.

A comprehensive list and description for all of the statutory and regulatory terms and conditions that apply to the TTP are set forth in FTA's Master Agreement for the TTP available on FTA's Web site at: *http://www.fta.dot.gov/17861_18441_ENG_HTML.htm*. In addition, as part of their application for grant award, FTA will require selected tribes to sign the Certifications and Assurances for the fiscal year in which they apply for a grant. FTA has provided information concerning

Certifications and Assurances in Appendix B of this notice.

VIII. Application and Submission Information

This notice includes all the information that a tribe will need to apply for competitive selection. It is available on the FTA Web site at *http://www.fta.dot.gov*. FTA will announce final selections on the Web site and in the **Federal Register**. FTA will also post a synopsis of this announcement on the government-wide electronic grants Web site at *http://www.grants.gov*.

IX. Guidelines for Preparing Grant Application

FTA is conducting a national solicitation for applications under the TTP. Project selection will be made on a competitive basis. FTA will divide the applications into three categories for the purpose of reviewing and selecting projects to be funded:

A. Start ups—applications for funding of new transit service;

B. Existing transit services—applications for funding of enhancements or expansion of existing transit services (including continuation of funding for start-ups selected for FY 2006 funding); and

C. Planning—applications for funding of planning studies and operational planning.

The application should provide information on all items for which tribes are requesting funding in FY 2007, and indicate the specific category in which the tribe is applying.

X. Application Content

A. Applicant Information

1. Name of federally recognized tribe and, if appropriate, the specific tribal agency submitting the application.

2. Dun and Bradstreet (D&B) Data Universal Numbering System (DUNS) number if available. (**Note:** If selected, applicant will be required to provide DUNS number prior to grant award, and DUNS number is required for submitting through grants.gov).

3. Contact information for notification of project selection: Contact name, address, and fax and phone number.

4. Description of public transportation services currently provided by tribe if any including areas served.

5. Name of person(s) authorized to apply on behalf of tribe (signed transmittal letter should accompany application if submitted in hard copy or e-mail).

B. Technical, Legal, and Financial Capacity to Implement the Proposed Project

Tribes that cannot demonstrate adequate capacity in technical, legal and financial areas will not be considered for funding. Every application must describe the tribe's technical, legal, and financial capacity to implement the proposed project.

1. *Legal Capacity:* Provide documentation or other evidence to show that the applicant is a Federally recognized tribe. Also, who is the authorized representative to execute legal agreements with FTA on behalf of the tribe? If currently operating transit service, does the tribe have appropriate Federal or State operating authority?

2. *Technical Capacity:* Give examples of the tribe's management of other Federal projects. What resources does the tribe have to implement a transit project?

3. *Financial Capacity:* Does the tribe have adequate financial systems in place to receive and manage a Federal grant? Describe the tribe's financial systems and controls.

C. Project Information

1. *Budget:* Provide the Federal amount requested for each purpose for which funds are sought and any funding from other sources that will be provided. If applying for a multi year project (not to exceed 4 years), show annual request for each year by budget line item.

2. *Project Description:* Indicate the category for which funding is requested i.e., Start-ups, Enhancements or replacements of existing transit services, or Planning studies or operational planning grants. Provide a summary description of the proposed project and how it will be implemented (e.g., number and type of vehicles, service area, schedules, type of services, fixed route or demand responsive, route miles (if fixed route) and size of service area, major origins and destinations, population served, and whether the tribe provide the service directly or contract for services and how will vehicles be maintained.

3. *Project Timeline:* Include significant milestones such as date of contract for purchase of vehicle(s), actual or expected delivery date of vehicles, and service start up dates.

D. Application Evaluation Criteria

Applications for funding of transit services should address the application criteria based on project to be funded (for more detail see section XII)

1. *Criterion 1:* Project Planning and Coordination.

2. *Criterion 2:* Demonstration of Need.

3. *Criterion 3:* Benefits of Project.

4. *Criterion 4:* Financial Commitment and Operating Capacity.

Applications for planning grants should address the criteria in section XII, C of this notice.

E. Submission Dates and Times

Applicants may submit complete applications for the TTP in one of the three ways: electronically through grants.gov, in hard copy to Federal Transit Administration, 1200 New Jersey Avenue, SE., Washington, DC 20590, *Attention:* Lorna R. Wilson; or sending by e-mail to *fta.tribalprogram@dot.gov*. by August 2, 2007 or submitted electronically through the Grants.gov Web site by the same date. FTA will announce grant selections when the competitive selection process is complete.

F. Intergovernmental Review

This program is not subject to Executive Order 12372, ''Intergovernmental Review of Federal Programs.''

G. Funding Restrictions

FTA will only consider applications for funding from eligible recipients for eligible activities (see section VI). Due to funding limitations, applicants that are selected for funding may receive less than the amount requested. The application process will allow an Indian tribe to apply for multiple years of funding not to exceed four years. No more than $25,000 in funding will be awarded per planning grant. The remaining funds will be made available for applications for funding of start up or new systems, and enhancements or expansion of existing transit service.

H. Other Submission Requirements

Applicants submitting hard copies should submit five (5) copies of their project proposal application to the Federal Transit Administration, 1200 New Jersey Avenue, SE., Washington, DC 20059, *Attention:* Lorna Wilson, or apply electronically through the government-wide electronic grant application portal at *www.grants.gov*. Alternatively, applicants may submit applications as an e-mail attachment to mailbox: *fta.tribalprogram@dot.gov*. Applicants applying by e-mail must fax signature documents to 202–366–7951, *Attention:* Lorna Wilson.

XI. Application Review Process

A. Competitive Selection Process

FTA will divide applications into three categories. The three evaluation categories are as follows:

• Start-ups—Applications for funding of new transit service.

• Existing transit services—Applications for funding of enhancements or expansion of existing transit services (including continuation of funding for start-ups selected for FY 2006 funding).

• Planning—Applications for funding of transit planning studies and/or operational planning.

Applications will be grouped into their respective category for review and scoring purposes. Applications for planning will be evaluated using a pass/fail system, whereas start-up and existing transit services applications will be scored based on the evaluation criteria to determine rank for funding award determination purposes. An applicant can receive up to 25 points for each evaluation criteria.

FTA intends to award the full amount of funding available in FY 2007 for the TTP. FTA encourages applicants to review the evaluation criteria and all other related application information prior to preparation of application. Applicants may receive technical assistance for application development by contacting their FTA regional Tribal liaison, Tribal Transportation Assistance Program (TTAP) center, or the National Rural Transportation Assistance Program (RTAP) office. Contact information for technical assistance can be found in Appendix C.

B. Evaluation Criteria

1. Project Planning and Coordination (25 Points)

In this section, the applicant should describe how the proposed project was developed and demonstrate that there is a sound basis for the project and that it is ready to implement if funded. Information may vary depending on whether the tribe has a formal plan that includes transit.

a. Applicants without a formal plan that includes transit are advised to consider and address the following areas:

i. Provide a detailed project description including the proposed service, vehicle and facility needs and other pertinent characteristics of the proposed service implementation.

ii. Identify existing transportation services available to the tribe and discuss whether the proposed project will provide opportunities to coordinate service with existing transit services including human service agencies, intercity bus services, or other public transit providers.

iii. Discuss the level of support either by the community and/or tribal government for the proposed project.

iv. Describe the implementation schedule for the proposed project such as time frame, staffing, and procurement.

b. Applicants with a formal transit plan are advised to consider and address the following areas:

i. Describe the planning document and/or the planning process conducted to identify the proposed project.

ii. Describe how the mobility and client access needs of tribal human service agencies were considered in the planning.

iii. Describe what opportunities for public participation were provided in the planning process and how the proposed transit service or existing service has been coordinated with transportation provided for the clients of human service agencies, with intercity bus transportation in the area, or with any other rural public transit providers.

iv. Describe how the proposed service complements rather than duplicates any currently available services.

v. Describe the implementation schedule for the proposed project, including time frame, staffing, procurements, etc.

vi. Describe any other planning or coordination efforts that were not mentioned above.

c. Based on the information provided as discussed in the above section, proposals will be rated on the following:

i. Is there a sound basis for the proposed project?

ii. Is the project ready to implement?

2. Demonstration of Need (25 Points)

In this section, the application should demonstrate the transit needs of the tribe and discuss how the proposed transit improvements will address the identified transit needs of the tribe. Applications may include information such as destinations and services not currently accessible by transit, need for access to jobs or health care, special needs of the elderly and individuals with disabilities, income-based community needs, or other mobility needs.

Based on the information provided, the proposals will be rated on the following:

a. Is there a demonstrated need for the project?

b. How well does the project fulfill the need?

3. Benefits of Project (25 Points)

In this section, applications should identify expected project benefits. Possible examples include increased ridership and daily trips, improved service, improved operations and coordination, and economic benefits to the community.

Benefits can be demonstrated by identifying the population of tribal members and non-tribal members in the proposed project service area and estimating the number of daily, one-way trips the transit service will provide and or the number of individual riders. There may be many other, less quantifiable, benefits to the tribe and surrounding community from this project. Please document, explain or show the benefits in whatever format is reasonable to present them.

Based on the information provided, proposals will be rated based on:

a. Will the project improve transit efficiency or increase ridership?

b. Will the project provide improved mobility for the tribe?

c. Will the project improve access to important destinations and services?

d. Are there other qualitative benefits?

4. Financial Commitment and Operating Capacity (25 Points)

In this section, the application should identify any other funding sources used by the tribe to support existing or proposed transit services, including human service transportation funding, Indian Reservation Roads, or other FTA programs such as the Job Access and Reverse Commute (JARC), New Freedom, section 5311, section 5310, or section 5309 bus and bus facilities funding.

For existing services, the application should show how TTP funding will supplement (not duplicate or replace) current funding sources. If the transit system was previously funded under section 5311 through the State's apportionment, describe how requested TTP funding will expand available services.

Describe any other resources the tribe will contribute to the project, including in-kind contributions, commitments of support from local businesses, donations of land or equipment, and human resources, and describe to what extent does the new project or funding for existing service leverage other funding.

The tribe should show its ability to manage programs by demonstrating the existing programs it administers, in any area of expertise such as human services. Based on the information provided the proposals will be rated on the extent to which the proposal demonstrates that:

a. This project provides new services or complements existing service.

b. TTP funding does not replace existing funding.

c. Tribe has or will provide non-financial support to project.

d. Tribe has demonstrated ability to provide other services or manage other programs.

e. Project funds are used in coordination with other services for efficient utilization of funds.

C. Proposals for Planning Grants

For planning grants, the applications should describe, in no more than three pages, the need for and a general scope of the proposed study.

1. Criteria: Need for Planning Study.

Based on the information provided, proposals will be rated pass/fail based on the following:

a. Is the tribe committed to planning for transit?

b. Is the scope of the proposed study for tribal transit?

D. Review and Selection Process

Each application will be screened by a panel of members including FTA Headquarters, and regional staff and representatives of the Indian Reservation Roads Program. Incomplete or non-responsive applications will be disqualified. FTA will make an effort to award a grant to as many qualified applicant as possible.

XII. Award Administration Information

FTA will award grants directly to federally recognize Indian tribes for the projects selected through this competition. Following publication of the selected recipients, projects, and amounts, FTA regional staff will assist the successful applicants to prepare an electronic application for grant award. At that time, the tribe will be required to sign the Certification and Assurances contained in Appendix B. The Master Agreement is available on FTA's Web site at *http://www.fta.dot.gov/17861_18441_ENG_HTML.htm*.

Applicants that are selected for grant awards under the TTP will be required to formally designate, by resolution or other formal tribal action, an authorized representative who will have the authority to execute grant agreements on behalf of the Indian tribe with FTA and who will also have the authority on behalf of the Indian tribe to execute FTA's Annual List of Certifications and Assurances.

FTA will notify all applicants, both those selected for funding and those not selected, when the competitive selection process is complete. Projects selected for funding will be published in a **Federal Register** notice.

XIII. Other Information

A. Technical Assistance

Technical assistance regarding these requirements is available from each FTA regional office. The regional offices will contact those applicants selected for funding regarding procedures for making the required certifications and assurances to FTA before grants are made and will provide assistance in preparing the documentation necessary for grant award.

B. Certifications and Assurances

Applicants that are selected and formally notified of FTA's intention to award a grant under the TTP will be required to complete and execute FTA's Annual list of Certification and Assurances in accordance with the procedures described in this Notice of Funding Availability. The Annual List of Certifications and Assurances is attached in Appendix B for informational purposes only.

C. Reporting

Title 49 U.S.C. 5335 requires recipients, including tribes, of Section 5311 program funds to report data, specified in 49 U.S.C. 5311(b)(4) to the National Transit Database (NTD). Specific procedures and data requirements for tribes are being developed and will be available on the NTD Web site. For technical assistance, contact Lauren Tuzikow at 703–462–5233, *e-mail: Lauren.tuzikow@TSPUSA.com*. For NTD program information, contact Gary DeLorme at 202–366–1652. Annual progress reports and financial status reports will be required of all recipients.

D. Agency Contact(s)

Contact the appropriate FTA regional Tribal Liaison (Appendix A) for application specific information and issues For general program information, contact Lorna R. Wilson, Office of Transit Programs, at (202) 366–2053, *e-mail: Lorna.Wilson@dot.gov*. A TDD is available at 1–800–877–8339 (TDD/FIRS).

Issued in Washington, DC, this 29th day of March, 2007.

James S. Simpson,

Administrator.

Appendix A—FTA Regional Offices and Tribal Transit Liaisons

Region I—Massachusetts, Rhode Island, Connecticut, New Hampshire, Vermont and Maine, Richard H. Doyle, FTA Regional Administrator, Volpe National Transportation Systems Center, Kendall Square 55 Broadway, Suite 920, Cambridge, MA 02142–1093, Phone: (617) 494–2055, Fax: (617) 494–2865, Regional Tribal Liaison: Judi Molloy.

Region II—New York, New Jersey Brigid Hynes-Cherin, FTA Regional Administrator, One Bowling Green, Room 429, New York, NY 10004–1415, Phone: (212) 668–2170, Fax: (212) 668–2136, Regional Tribal Liaison: Rebecca Reyes-Alicea.

Region III—Pennsylvania, Maryland, Virginia, West Virginia, Delaware, Washington, DC, Herman Shipman, Acting FTA Regional Administrator, 1760 Market Street, Suite 500, Philadelphia, PA 19103–4124, Phone: (215) 656–7100, Fax: (215) 656–7260,

Region IV—Georgia, North Carolina, South Carolina, Florida, Mississippi, Tennessee, Kentucky, Alabama, Puerto Rico, Virgin Islands, Yvette G. Taylor, FTA Regional Administrator, 61 Forsyth Street, S.W., Suite 17T50, Atlanta, GA 30303, Phone: (404) 562–3500, Fax: (404) 562–3505, Regional Tribal Liaisons: Jamie Pfister and James Garland.

Region V—Illinois, Indiana, Ohio, Wisconsin, Minnesota, Michigan, Marisol R. Simon, FTA Regional Administrator, 200 West Adams Street, Suite 320, Chicago, IL 60606–5232, Phone: (312) 353–2789, Fax: (312) 886–0351, Regional Tribal Liaisons: William Wheeler.

Region VI—Texas, New Mexico, Louisiana, Arkansas, Oklahoma, Robert Patrick, FTA Regional Administrator, 819 Taylor Street, Room 8A36, Ft. Worth, TX 76102, Phone: (817) 978–0550, Fax: (817) 978–0575, Regional Tribal Liaison: Lynn Hayes.

Region VII—Iowa, Nebraska, Kansas, Missouri, Mokhtee Ahmad, FTA Regional Administrator, 901 Locust Street, Suite 404, Kansas City, MO 64106, Phone: (816) 329–3920, Fax: (816) 329–3921, Regional Tribal Liaisons: Joni Roeseler and Cathy Monroe.

Region VIII—Colorado, North Dakota, South Dakota, Montana, Wyoming, Utah, Letitia A. Thompson, Acting FTA Regional Administrator, 12300 West Dakota Avenue, Suite 310, Lakewood, CO 80228–2583, Phone: (720) 963–3300, Fax: (720) 963–3333, Regional Tribal Liaisons: Jennifer Stewart and David Beckhouse.

Region IX—California, Arizona, Nevada, Hawaii, American Samoa, Guam, Leslie Rogers, FTA Regional Administrator, 201 Mission Street, Suite 1650, San Francisco, CA 94105–1831, Phone: (415) 744–3133, Fax: (415) 744–2726, Regional Tribal Liaison: Donna Turchie.

Region X—Washington, Oregon, Idaho, Alaska, Richard Krochalis, FTA Regional Administrator, Jackson Federal Building, 915 Second Avenue, Suite 3142, Seattle, WA 98174–1002, Phone: (206) 220–7954, Fax: (206) 220–7959, Regional Tribal Liaisons: Bill Ramos and Annette Clothier.

Appendix B—Certifications and Assurances

Federal Fiscal Year 2007 Certifications and Assurances for the Federal Transit Administration Tribal Transit Program

In accordance with 49 U.S.C. 5323(n), the following certifications and assurances have been compiled for the Federal Transit

Administration (FTA) Public Transportation on Indian Reservation Program (Tribal Transit Program) authorized by 49 U.S.C. 5311(c)(1).

The Applicant understands and agrees that these certifications and assurances are pre-award requirements and do not encompass all statutory and regulatory requirements that may apply to the Applicant or its Project. A comprehensive list of those requirements will be contained in the Grant Agreement including the Master Agreement accompanying an award under the Tribal Transit Program (TTP).

FTA and the Applicant also understand and agree that not every certification and assurance will apply to every Project for which FTA provides Federal financial assistance through the TTP. The type of Project will determine which requirements apply. For example FTA believes that the following requirements within the listed certifications and assurances will have limited, if any, impact:

1. Many provisions required by the Office of Management and Budget (OMB) set forth in Certification F involve requirements that in most cases will not be invoked, such as:

a. Title III of the Uniform Relocation and Real Property Acquisition Policies Act, as amended, and implementing U.S. Department Of Transportation (U.S. DOT) regulations will apply only when the Applicant acquires real property with FTA assistance.

b. Title II of the Uniform Relocation and Real Property Acquisition Policies Act, as amended, and implementing U.S. DOT regulations will apply only when the Applicant's project requires relocation of a person or business; and the Lead-Based Paint Poisoning Prevention Act is invoked only in connection with residential construction, not likely to take place under the TTP.

c. The Flood Disaster Protection Act applies to projects in flood hazard areas.

d. Only for construction projects will the Davis-Bacon Act, Seismic Safety regulations, and OMB engineering supervision requirements apply.

e. Many environmental protection requirements are limited to the specific problem addressed by the statute. If, for example, the project will not affect endangered species, the requirements of the Endangered Species Act will not be invoked.

2. With respect to Certification H, ''Bus Testing,'' only if the Applicant acquires the first bus of a new bus model or the first bus of a new major configuration of a new bus will FTA's Bus Testing requirements be invoked.

Except to the extent that FTA determines otherwise in writing, each Applicant for TTP assistance, however, must provide all certifications and assurance set forth below. FTA may not award any Federal assistance under the TTP until the Applicant provides these certifications and assurances.

A. Assurance of Authority of the Applicant and Its Representative

The authorized representative of the Applicant and the attorney who sign these certifications, assurances, and agreements affirm that both the Applicant and its authorized representative have adequate authority under Federal and Indian tribal law, regulations, or by-laws to:

(1) Execute and file the application for Federal assistance on behalf of the Applicant;

(2) Execute and file the required certifications, assurances, and agreements on behalf of the Applicant binding the Applicant; and

(3) Execute grant agreements with FTA on behalf of the Applicant.

B. Standard Assurances

The Applicant assures that it will comply with all applicable Federal statutes and regulations in carrying out any project supported by an FTA grant. The Applicant agrees that it is under a continuing obligation to comply with the terms and conditions of the Grant Agreement issued for its project with FTA. The Applicant recognizes that Federal laws and regulations may be modified from time to time and those modifications may affect project implementation. The Applicant understands that Presidential executive orders and Federal directives, including Federal policies and program guidance may be issued concerning matters affecting the Applicant or its project. The Applicant agrees that the most recent Federal laws, regulations, and directives will apply to the project, unless FTA issues a written determination otherwise.

C. Applicant's Capacity to Comply With Relevant Section 5311 Requirements

The Applicant assures that:

(1) It has or will have the necessary legal, financial, and managerial capability to apply for, receive, and disburse Federal assistance authorized for 49 U.S.C. 5311; and to carry out each project, including the safety and security aspects of that project;

(2) It has or will have satisfactory continuing control over the use of project equipment and facilities;

(3) The project equipment and facilities will be adequately maintained; and

(4) Its project will achieve maximum feasible coordination with transportation service assisted by other Federal sources.

D. Nondiscrimination Assurance

As required by Title VI of the Civil Rights Act of 1964, as amended, 42 U.S.C. 2000d, and by U.S. DOT regulations, ''Nondiscrimination in Federally-Assisted Programs of the Department of Transportation—Effectuation of Title VI of the Civil Rights Act,'' 49 CFR part 21 at 21.7, the Applicant assures that it will comply with all requirements imposed by or issued pursuant to 42 U.S.C. 2000d, and 49 CFR part 21, so that no person in the United States, on the basis of race, color, or national origin, will be excluded from participation in, be denied the benefits of, or otherwise be subjected to discrimination in any program or activity (particularly in the level and quality of transportation services and transportation-related benefits) for which the Applicant receives Federal assistance awarded by the U.S. DOT or FTA.

Specifically, during the period in which Federal assistance is extended to the project, or project property is used for a purpose for which the Federal assistance is extended or for another purpose involving the provision of similar services or benefits, or as long as the Applicant retains ownership or possession of the project property, whichever is longer, the Applicant assures that:

(1) Each project will be conducted, property acquisitions will be undertaken, and project facilities will be operated in accordance with all applicable requirements imposed by or issued pursuant to 42 U.S.C. 2000d, and 49 CFR part 21, and understands that this assurance extends to its entire facility and to facilities operated in connection with the project.

(2) It will promptly take the necessary actions to effectuate this assurance, including notifying the public that complaints of discrimination in the provision of transportation-related services or benefits may be filed with U.S. DOT or FTA. Upon request by U.S. DOT or FTA, the Applicant assures that it will submit the required information pertaining to its compliance with these provisions.

(3) It will include in each subagreement, property transfer agreement, third party contract, third party subcontract, or participation agreement adequate provisions to extend the requirements imposed by or issued pursuant to 42 U.S.C. 2000d and 49 CFR part 21 to other parties involved therein including any subrecipient, transferee, third party contractor, third party subcontractor at any level, successor in interest, or any other participant in the project.

(4) Should it transfer real property, structures, or improvements financed with Federal assistance provided by FTA to another party, any deeds and instruments recording the transfer of that property shall contain a covenant running with the land assuring nondiscrimination for the period during which the property is used for a purpose for which the Federal assistance is extended or for another purpose involving the provision of similar services or benefits.

(5) The United States has a right to seek judicial enforcement with regard to any matter arising under the Act, regulations, and this assurance.

(6) It will make any changes in its Title VI implementing procedures as U.S. DOT or FTA may request to achieve compliance with the requirements imposed by or issued pursuant to 42 U.S.C. 2000d and 49 CFR part 21.

E. Assurance of Nondiscrimination on the Basis of Disability

As required by U.S. DOT regulations, ''Nondiscrimination on the Basis of Handicap in Programs and Activities Receiving or Benefiting from Federal Financial Assistance,'' at 49 CFR 27.9, the Applicant assures that, as a condition to the approval or extension of any Federal assistance awarded by FTA to construct any facility, obtain any rolling stock or other equipment, undertake studies, conduct research, or to participate in or obtain any benefit from any program administered by FTA, no otherwise qualified person with a disability shall be, solely by reason of that disability, excluded from participation in, denied the benefits of, or otherwise subjected to discrimination in

any program or activity receiving or benefiting from Federal assistance administered by the FTA or any entity within U.S. DOT. The Applicant assures that project implementation and operations so assisted will comply with all applicable requirements of U.S. DOT regulations implementing the Rehabilitation Act of 1973, as amended, 29 U.S.C. 794, et seq., and the Americans with Disabilities Act of 1990, as amended, 42 U.S.C. 12101 et seq., and implementing U.S. DOT regulations at 49 CFR parts 27, 37, and 38, and any other applicable Federal laws that may be enacted or Federal regulations that may be promulgated.

F. U.S. Office of Management and Budget (OMB) Assurances

Consistent with OMB assurances set forth in SF–424B and SF–424D, the Applicant assures that, with respect to itself and its project, the Applicant:

(1) Has the legal authority to apply for Federal assistance and the institutional, managerial, and financial capability to ensure proper planning, management, and completion of the project described in its application;

(2) Will give FTA, the Comptroller General of the United States, and, if appropriate, the state, through any authorized representative, access to and the right to examine all records, books, papers, or documents related to the award; and will establish a proper accounting system in accordance with generally accepted accounting standards or agency directives;

(3) Will establish safeguards to prohibit employees from using their positions for a purpose that constitutes or presents the appearance of personal or organizational conflict of interest or personal gain;

(4) Will initiate and complete the work within the applicable project time periods following receipt of FTA approval;

(5) Will comply with all applicable Federal statutes relating to nondiscrimination including, but not limited to:

(a) Title VI of the Civil Rights Act, 42 U.S.C. 2000d, which prohibits discrimination on the basis of race, color, or national origin;

(b) Title IX of the Education Amendments of 1972, as amended, 20 U.S.C. 1681 through 1683, and 1685 through 1687, and U.S. DOT regulations, ''Nondiscrimination on the Basis of Sex in Education Programs or Activities Receiving Federal Financial Assistance,'' 49 CFR part 25, which prohibit discrimination on the basis of sex;

(c) Section 504 of the Rehabilitation Act of 1973, as amended, 29 U.S.C. 794 et seq., which prohibits discrimination on the basis of disability;

(d) The Age Discrimination Act of 1975, as amended, 42 U.S.C. 6101 through 6107, which prohibits discrimination on the basis of age;

(e) The Drug Abuse Office and Treatment Act of 1972, Pub. L. 92–255, March 21, 1972, and amendments thereto, 21 U.S.C. 1174 et seq. relating to nondiscrimination on the basis of drug abuse;

(f) The Comprehensive Alcohol Abuse and Alcoholism Prevention Act of 1970, Pub. L. 91–616, Dec. 31, 1970, and amendments thereto, 42 U.S.C. 4581 et seq. relating to nondiscrimination on the basis of alcohol abuse or alcoholism;

(g) The Public Health Service Act of 1912, as amended, 42 U.S.C. 290dd–3 and 290ee–3, related to confidentiality of alcohol and drug abuse patient records;

(h) Title VIII of the Civil Rights Act, 42 U.S.C. 3601 et seq., relating to nondiscrimination in the sale, rental, or financing of housing; and

(i) Any other nondiscrimination statute(s) that may apply to the project;

(6) To the extent applicable, will comply with, or has complied with, the requirements of Titles II and III of the Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970, as amended, (Uniform Relocation Act) 42 U.S.C. 4601 et seq., which, among other things, provide for fair and equitable treatment of persons displaced or persons whose property is acquired as a result of Federal or federally assisted programs. These requirements apply to all interests in real property acquired for project purposes and displacement caused by the project regardless of Federal participation in any purchase. As required by sections 210 and 305 of the Uniform Relocation Act, 42 U.S.C. 4630 and 4655, and by U.S. DOT regulations, ''Uniform Relocation Assistance and Real Property Acquisition for Federal and Federally Assisted Programs,'' 49 CFR 24.4, the Applicant assures that it has the requisite authority under its applicable tribal government law to comply with the requirements of the Uniform Relocation Act, 42 U.S.C. 4601 et seq., and U.S. DOT regulations, ''Uniform Relocation Assistance and Real Property Acquisition for Federal and Federally Assisted Programs,'' 49 CFR part 24, and will comply with that Act or has complied with that Act and those implementing regulations, including but not limited to the following:

(a) The Applicant will adequately inform each affected person of the benefits, policies, and procedures provided for in 49 CFR part 24;

(b) The Applicant will provide fair and reasonable relocation payments and assistance as required by 42 U.S.C. 4622, 4623, and 4624; 49 CFR part 24; and any applicable FTA procedures, to or for families, individuals, partnerships, corporations, or associations displaced as a result of any project financed with FTA assistance;

(c) The Applicant will provide relocation assistance programs offering the services described in 42 U.S.C. 4625 to such displaced families, individuals, partnerships, corporations, or associations in the manner provided in 49 CFR part 24;

(d) Within a reasonable time before displacement, the Applicant will make available comparable replacement dwellings to displaced families and individuals as required by 42 U.S.C. 4625(c)(3);

(e) The Applicant will carry out the relocation process in such manner as to provide displaced persons with uniform and consistent services, and will make available replacement housing in the same range of choices with respect to such housing to all displaced persons regardless of race, color, religion, or national origin;

(f) In acquiring real property, the Applicant will be guided to the greatest extent practicable under state law, by the real property acquisition policies of 42 U.S.C. 4651 and 4652;

(g) The Applicant will pay or reimburse property owners for necessary expenses as specified in 42 U.S.C. 4653 and 4654, with the understanding that FTA will provide Federal financial assistance for the Applicant's eligible costs of providing payments for those expenses, as required by 42 U.S.C. 4631;

(h) The Applicant will execute such amendments to third party contracts and subagreements financed with FTA assistance and execute, furnish, and be bound by such additional documents as FTA may determine necessary to effectuate or implement the assurances provided herein; and

(i) The Applicant agrees to make these assurances part of or incorporate them by reference into any third party contract or subagreement, or any amendments thereto, relating to any project financed by FTA involving relocation or land acquisition and provide in any affected document that these relocation and land acquisition provisions shall supersede any conflicting provisions;

(7) To the extent applicable, will comply with the Davis-Bacon Act, as amended, 40 U.S.C. 3141 et seq., the Copeland ''Anti-Kickback'' Act, as amended, 18 U.S.C. 874, and the Contract Work Hours and Safety Standards Act, as amended, 40 U.S.C. 3701 et seq., regarding labor standards for federally assisted projects;

(8) To the extent applicable, will comply with the flood insurance purchase requirements of section 102(a) of the Flood Disaster Protection Act of 1973, as amended, 42 U.S.C. 4012a(a), requiring the Applicant and its subrecipients in a special flood hazard area to participate in the program and purchase flood insurance if the total cost of insurable construction and acquisition is $10,000 or more;

(9) To the extent applicable, will comply with the Lead-Based Paint Poisoning Prevention Act, 42 U.S.C. 4831(b), which prohibits the use of lead-based paint in the construction or rehabilitation of residence structures;

(10) To the extent applicable, will not dispose of, modify the use of, or change the terms of the real property title or other interest in the site and facilities on which a construction project supported with FTA assistance takes place without permission and instructions from FTA;

(11) To the extent required by FTA, will record the Federal interest in the title of real property, and will include a covenant in the title of real property acquired in whole or in part with Federal assistance funds to assure nondiscrimination during the useful life of the project;

(12) To the extent applicable, will comply with FTA provisions concerning the drafting, review, and approval of construction plans and specifications of any construction project supported with FTA assistance. As required by U.S. DOT regulations, ''Seismic Safety,'' 49 CFR 41.117(d), before accepting delivery of any building financed with FTA assistance, it will obtain a certificate of compliance with the seismic design and construction requirements of 49 CFR part 41;

(13) To the extent applicable, will provide and maintain competent and adequate engineering supervision at the construction site of any project supported with FTA assistance to ensure that the complete work conforms with the approved plans and specifications, and will furnish progress reports and such other information as may be required by FTA or the state;

(14) To the extent applicable, will comply with any applicable environmental standards that may be prescribed to implement the following Federal laws and executive orders:

(a) Institution of environmental quality control measures under the National Environmental Policy Act of 1969, as amended, 42 U.S.C. 4321 through 4335 and Executive Order No. 11514, as amended, 42 U.S.C. 4321 note;

(b) Notification of violating facilities pursuant to Executive Order No. 11738, 42 U.S.C. 7606 note;

(c) Protection of wetlands pursuant to Executive Order No. 11990, 42 U.S.C. 4321 note;

(d) Evaluation of flood hazards in floodplains in accordance with Executive Order No. 11988, 42 U.S.C. 4321 note;

(e) Assurance of project consistency with the approved state management program developed pursuant to the requirements of the Coastal Zone Management Act of 1972, as amended, 16 U.S.C. 1451 through 1465;

(f) Conformity of Federal actions to State (Clean Air) Implementation Plans under section 176(c) of the Clean Air Act of 1955, as amended, 42 U.S.C. 7401 through 7671q;

(g) Protection of underground sources of drinking water under the Safe Drinking Water Act of 1974, as amended, 42 U.S.C. 300f through 300j–6;

(h) Protection of endangered species under the Endangered Species Act of 1973, as amended, 16 U.S.C. 1531 through 1544; and

(i) Environmental protections for Federal transportation programs, including, but not limited to, protections for parks, recreation areas, or wildlife or waterfowl refuges of national, state, local, or tribal government significance or any land from a historic site of national, state, local, or tribal government significance to be used in a transportation project as required by 49 U.S.C. 303(b) and 303(c);

(j) Protection of the components of the national wild and scenic rivers systems, as required under the Wild and Scenic Rivers Act of 1968, as amended, 16 U.S.C. 1271 through 1287; and

(k) Provision of assistance to FTA in complying with section 106 of the National Historic Preservation Act of 1966, as amended, 16 U.S.C. 470f; with the Archaeological and Historic Preservation Act of 1974, as amended, 16 U.S.C. 469 through 469c; and with Executive Order No. 11593 (identification and protection of historic properties), 16 U.S.C. 470 note;

(15) Because a tribal government is not covered by the Hatch Act, the Applicant is not required to comply with the requirements of the Hatch Act, 5 U.S.C. 1501 through 1508 and 7324 through 7326, which limit the political activities of state and local agencies and their officers and employees whose primary employment activities are financed in whole or part with Federal funds including a Federal grant agreement except, in accordance with 49 U.S.C. 5307(k)(2) and 23 U.S.C. 142(g), the Hatch Act does not apply to a nonsupervisory employee of a public transportation system (or of any other agency or entity performing related functions) receiving FTA assistance to whom that Act does not otherwise apply;

(16) To the extent applicable, will comply with the National Research Act, Pub. L. 93–348, July 12, 1974, as amended, 42 U.S.C. 289 et seq., and U.S. DOT regulations, ''Protection of Human Subjects,'' 49 CFR part 11, regarding the protection of human subjects involved in research, development, and related activities supported by Federal assistance;

(17) To the extent applicable, will comply with the Laboratory Animal Welfare Act of 1966, as amended, 7 U.S.C. 2131 et seq., and U.S. Department of Agriculture regulations, ''Animal Welfare,'' 9 CFR subchapter A, parts 1, 2, 3, and 4, regarding the care, handling, and treatment of warm blooded animals held or used for research, teaching, or other activities supported by Federal assistance;

(18) Will have performed the financial and compliance audits as required by the Single Audit Act Amendments of 1996, 31 U.S.C. 7501 *et seq.*, OMB Circular A–133, ''Audits of States, Local Governments, and Non-Profit Organizations,'' Revised, and the most recent applicable OMB A–133 Compliance Supplement provisions for the U.S. DOT; and

(19) To the extent applicable, will comply with all applicable provisions of all other Federal laws, regulations, and directives governing the project, except to the extent that FTA has expressly approved otherwise in writing.

G. Procurement Compliance

In accordance with 49 CFR 18.36(g)(3)(ii), the Applicant certifies that its procurement system will comply with the requirements of 49 CFR 18.36, or will inform FTA promptly that its procurement system does not comply with 49 CFR 18.36.

H. Bus Testing

As required by 49 U.S.C. 5318 and FTA regulations, ''Bus Testing,'' at 49 CFR 665.7, the Applicant certifies that, before expending any Federal assistance to acquire the first bus of any new bus model or any bus model with a new major change in configuration or components, or before authorizing final acceptance of that bus (as described in 49 CFR part 665), the bus model:

A. Will have been tested at FTA's bus testing facility; and

B. Will have received a copy of the test report prepared on the bus model.

I. Charter Service Agreement

(1) As required by 49 U.S.C. 5323(d) and (g) and FTA regulations, ''Charter Service,'' at 49 CFR 604.7, the Applicant agrees that it and each subrecipient and third party contractor at any tier will:

(a) Provide charter service that uses equipment or facilities acquired with Federal assistance authorized under 49 U.S.C. chapter 53 (except 49 U.S.C. 5310 or 5317), or under 23 U.S.C. 133 or 142 for transportation projects, only to the extent that there are no private charter service operators willing and able to provide the charter service that it or its subrecipients or third party contractors at any tier desire to provide, unless one or more of the exceptions in 49 CFR 604.9 applies; and

(b) Comply with the requirements of 49 CFR part 604 before providing any charter service using equipment or facilities acquired with Federal assistance authorized under 49 U.S.C. chapter 53 (except 49 U.S.C. 5310 or 5317), or under 23 U.S.C. 133 or 142 for transportation projects.

(2) The Applicant understands that:

(a) The requirements of 49 CFR part 604 will apply to any charter service it or its subrecipients or third party contractors provide,

(b) The definitions of 49 CFR part 604 will apply to this Charter Service Agreement, and

(c) A violation of this Charter Service Agreement may require corrective measures and imposition of penalties, including debarment from the receipt of further Federal assistance for transportation.

J. School Transportation Agreement

(1) As required by 49 U.S.C. 5323(f) and (g) and FTA regulations at 49 CFR 605.14, the Applicant agrees that it and each subrecipient or third party contractor at any tier will:

(a) Engage in school transportation operations in competition with private school transportation operators only to the extent permitted by 49 U.S.C. 5323(f) and (g), and Federal regulations; and

(b) Comply with the requirements of 49 CFR part 605 before providing any school transportation using equipment or facilities acquired with Federal assistance authorized under 49 U.S.C. chapter 53 or under 23 U.S.C. 133 or 142 for transportation projects.

(2) The Applicant understands that:

(a) The requirements of 49 CFR part 605 will apply to any school transportation service it or its subrecipients or third party contractors provide,

(b) The definitions of 49 CFR part 605 will apply to this School Transportation Agreement, and

(c) A violation of this School Transportation Agreement may require corrective measures and imposition of penalties, including debarment from the receipt of further Federal assistance for transportation.

K. Demand Responsive Service

As required by U.S. DOT regulations, ''Transportation Services for Individuals with Disabilities (ADA),'' at 49 CFR 37.77(d), the Applicant certifies that its demand responsive service offered to individuals with disabilities, including individuals who use wheelchairs, is equivalent to the level and quality of service offered to individuals without disabilities. When the Applicant's service is viewed in its entirety, the Applicant's service for individuals with disabilities is provided in the most integrated setting feasible and is equivalent with respect to: (1) Response time, (2) fares, (3) geographic service area, (4) hours and days of service, (5) restrictions on trip purpose, (6) availability of information and reservation capability, and

(7) constraints on capacity or service availability.

L. Alcohol Misuse and Prohibited Drug Use

As required by FTA regulations, ''Prevention of Alcohol Misuse and Prohibited Drug Use in Transit Operations,'' at 49 CFR part 655, subpart I, the Applicant certifies that it has established and implemented an alcohol misuse and anti-drug program, and has complied with or will comply with all applicable requirements of FTA regulations, ''Prevention of Alcohol Misuse and Prohibited Drug Use in Transit Operations,'' 49 CFR part 655.

M. National Intelligent Transportation Systems Architecture and Standards

An Applicant for FTA assistance for an Intelligent Transportation Systems (ITS) project, defined as any project that in whole or in part finances the acquisition of technologies or systems of technologies that provide or significantly contribute to the provision of one or more ITS user services as defined in the National ITS Architecture, will use its best efforts to ensure that any Intelligent Transportation System solutions used in its Project do not preclude interface with other Intelligent Transportation Systems in the Region. (See, FTA **Federal Register** notice dated, January 8, 2001 ''FTA National ITS Architecture Policy on Transit Projects'' (66 FR 1455, and other FTA Program Guidance that may be issued.)

Federal Fiscal Year 2006 Certifications and Assurances for the Tribal Transit Program

Signature Pages (Required of All Applicants for FTA Assistance for the Tribal Transit Program)

Affirmation of Applicant

Name of Applicant:

_____

Name and Relationship of Authorized Representative:

_____

BY SIGNING BELOW, on behalf of the Applicant, I declare that the Applicant has duly authorized me to make these certifications and assurances and bind the Applicant's compliance. Thus, the Applicant agrees to comply with all Federal statutes, regulations, executive orders, and Federal requirements applicable to each application for Tribal Transit Program assistance authorized by 49 U.S.C. 5311(c)(1) it makes to the Federal Transit Administration (FTA) in Federal Fiscal Year 2007.

The Applicant affirms the truthfulness and accuracy of the certifications and assurances it has made in the statements submitted herein with this document and any other submission made to FTA, and acknowledges that the provisions of the Program Fraud Civil Remedies Act of 1986, 31 U.S.C. 3801 et seq., as implemented by U.S. DOT regulations, ''Program Fraud Civil Remedies,'' 49 CFR part 31 apply to any certification, assurance or submission made to FTA. The criminal fraud provisions of 18 U.S.C. 1001 apply to any certification, assurance, or submission made in connection with the Tribal Transit Program and may apply to any other certification, assurance, or submission made in connection with any other program administered by FTA.

In signing this document, I declare under penalties of perjury that the foregoing certifications and assurances, and any other statements made by me on behalf of the Applicant are true and correct.

Signature: _____

Date: _____

Name: _____

Authorized Representative of Applicant

Affirmation of Applicant's Attorney

For (Name of Applicant):

_____

As the undersigned Attorney for the above named Applicant, I hereby affirm to the Applicant that it has authority under its tribal government law to make and comply with the certifications and assurances as indicated on the foregoing pages. I further affirm that, in my opinion, the certifications and assurances have been legally made and constitute legal and binding obligations on the Applicant.

I further affirm to the Applicant that, to the best of my knowledge, there is no legislation or litigation pending or imminent that might adversely affect the validity of these certifications and assurances, or of the performance of the project.

Signature: _____

Date: _____

Name: _____

Attorney for Applicant

[Each Applicant for FTA Tribal Transit Program assistance must provide an Affirmation of Applicant's Attorney pertaining to the Applicant's legal capacity. The Applicant may enter its signature in lieu of the Attorney's signature, provided the Applicant has on file this Affirmation, signed by the attorney and dated this Federal fiscal year, and the Attorney's Affirmation has been entered into the TEAM-Web system as an attachment.]

Appendix C—Technical Assistance Contacts

Tribal Technical Assistance Program (TTAP) Centers

TTAP—Alaska

Alaska Tribal Technical Assistance Program, NW & AK TTAP 329 Harbor Dr. #208, Sitka, AK 99835, Contact: Dan Moreno, Telephone: (800) 399–6376, Fax: (907) 747–5032, E-mail: *dmoreno@mail.ewu.edu,* Web: *http://www.ewu.edu/TTAP.*

TTAP—California

TTAP—California-Nevada, The National Center for American Indian Enterprise Development 11138 Valley Mall, Suite 200, El Monte, CA 91731, Contact: Lee Bigwater, Telephone: (626) 350–4446, Fax: (626) 442-7115.

TTAP—Colorado

Tribal Technical Assistance Program at Colorado State University, Rockwell Hall, Rm. 321, Colorado State University, Fort Collins, CO 80523–1276, Contact: Ronald Hall, Telephone: (800) 262–7623, Fax: (970) 491–3502, E-mail: *ronald.hall@colostate.edu,* Web: *http://ttap.colostate.edu/.*

TTAP—Michigan

Tribal Technical Assistance Program 301–E Dillman Hall, Michigan Technological University 1400 Townsend Dr, Houghton, MI 49931–1295, Contact: Bernard D. Alkire, Telephone: (888) 230–0688, Fax: (906) 487–1834, E-mail: *balkire@mtu.edu,* Web: *http://www.ttap.mtu.edu.*

TTAP—North Dakota

Northern Plains Tribal Technical Assistance Program, United Tribes Technical College 3315, University Drive, Bismarck, ND 58504, Contact: Dennis Trusty, Telephone: (701) 255–3285, ext. 1262, Fax: (701) 530–0635, E-mail: *nddennis@hotmail.com or dtrusty@uttc.edu,* Web: *http://www.uttc.edu/organizations/ttap/ttap.asp.*

TTAP—NW

Northwest Tribal Technical Assistance Program, Eastern Washington University Department of Urban Planning, Public & Health Administration, 216 Isle Hall, Cheney, WA 99004, Contact: David Frey, Telephone: (800) 583–3187, Fax: (509) 359–7485, E-mail: *rrolland@ewu.edu,* Web: *http://www.ewu.edu/TTAP.*

TTAP—Oklahoma

Tribal Technical Assistance Program at Oklahoma State University, Oklahoma State University, 5202 N. Richmond Hills Road, Stillwater, OK 74078–0001, Contact: James Self, Telephone: (405) 744–6049, Fax: (405) 744–7268, E-mail: *jim.self@okstate.edu,* Web: *http://ttap.okstate.edu.*

National RTAP (National Rural Transit Assistance Program), E-mail: *nationalrtap@apwa.net, http://www.nationalrtap.org/,* Dave Barr, 202–218–6722.

Community Transportation Association of America, The Resource Center—1800–891–0590, *http://www.ctaa.org/.*

[FR Doc. E7–6199 Filed 4–3–07; 8:45 am]

BILLING CODE 4910–57–P

DEPARTMENT OF TRANSPORTATION

Federal Transit Administration

Public Transportation on Indian Reservations Program; Tribal Transit Program

AGENCY: Federal Transit Administration (FTA), DOT.

ACTION: Notice of Award.

SUMMARY: The Federal Transit Administration (FTA) announces the selection of projects to be funded under Fiscal Year (FY) 2006 appropriations for the Tribal Transit Program (TTP), a program authorized by the Safe, Accountable, Flexible, and Efficient

Transportation Equity Act: A Legacy for Users (SAFETEA–LU).

FOR FURTHER INFORMATION CONTACT: Contact the appropriate FTA regional Tribal Liaison (Appendix A) for application-specific information and issues. For general program information, contact Lorna R. Wilson, Office of Transit Programs, at (202) 366–2053, e-mail: *Lorna.Wilson@dot.gov.* A TDD is available at 1–800–877–8339 (TDD/FIRS).

SUPPLEMENTARY INFORMATION: The Tribal Transit Program (TTP) established by Section 3013 SAFETEA–LU, Public Law 109–49 (August 15, 2005), under 49 U.S.C. 5311(c) makes funds available to federally recognized Indian tribes or Alaska Native villages, groups, or communities as identified by the Bureau of Indian Affairs (BIA) in the U.S. Department of the Interior for public transportation capital projects, operating costs and planning activities that are eligible costs under the Nonurbanized Area Formula Program (Section 5311).

A total of $7.92 million was made available for the program in FY 2006. A total of 95 applicants requested $22.1 million for funding for new transit service, enhancement or expansion of existing transit services, or planning studies and operational planning. The applications also included an additional $41,767,031 in requests for future year funds. FTA made project selections through a competitive process based on each applicant's responsiveness to the programs evaluation criteria outlined in FTA's August 15, 2006, **Federal Register** Notice: Notice of Funding Availability and Solicitation for FY 2006 TTP (71 FR 46959). FTA evaluated applications for planning grants on a pass/fail basis, whereas FTA evaluated applications for start up and existing transit services on a numeric score system. Because of the high demand for the funds available, many applicants selected for funding will receive less funding than they requested to enable FTA to support more of the most meritorious applications. However, all of the most highly qualified applicants received some funding.

This notice only addresses FY 2006 funding for projects. Tribes that sought funding for a multi-year project in response to the FY 2006 solicitation must submit a new application in response to the FY 2007 Notice of Funding Availability (NOFA) in order to be considered for FY 2007 funding.

The selected projects, providing $7.92 million to 63 tribes, breaks down as follows: $834,965 for transit planning studies and/or operational planning, $3,168,861 million for startup projects for new transit service, and $3,916,354 for enhancements or expansion of exiting transit services. Each of the 63 awardees, as well as the 32 applicants who were not selected for funding, will receive a letter explaining the funding decision. The successful applicants for FY 2006 are listed below.

Tribes that were not selected for the FY 2006 TTP will be invited to participate in FTA sponsored Tribal Technical Assistance Program workshops and events. One goal of the program is to better equip a tribe to compete for future year funding. This technical assistance will be open to all tribes.

Following publication of this notice, FTA regional offices will conduct a new grantee orientation. FTA's regional tribal liaison will contact each applicant selected for funding to discuss scheduling and event logistics.

FY 2006 Tribal Transit Grant Recipients

Tribe	State	Planning (in dollars)	Start-up (in dollars)	Ehancement (in dollars)	Project No.
Burns Paiute Tribe	Oregon	25,000			D2006–TRTR–0001
Caddo Nation	Oklahoma	25,000			D2006–TRTR–0002
Cherokee Nation	Oklahoma	25,000			D2006–TRTR–0003
Chickaloon Native Village	Arkansas	25,000			D2006–TRTR–0004
Choctaw Nation of Oklahoma	Oklahoma			$158,000	D2006–TRTR–0005
Cocopah Indian Tribe	Arizona			208,000	D2006–TRTR–0006
Confederated Salish and Kootenai Tribes	Montana			373,274	D2006–TRTR–0007
Confederated Tribes and Bands of the Yakama Nation's.	Washington		490,890		D2006–TRTR–0008
Confederated Tribes of the Colville Indian	Washington			156,000	D2006–TRTR–0009
Confederated Tribes of the Grand Ronde Community of Oregon.	Oregon		247,340		D2006–TRTR–0010
Coquille Tribe of Oregon	Oregon	25,000			D2006–TRTR–0011
Eastern Band of Cherokee Indians	North Carolina			100,000	D2006–TRTR–0012
Fallon Paiute-Shoshone Tribe	Nevada	25,000			D2006–TRTR–0013
Grand Portage Band of Chippewa Indians	Minnesota			60,000	D2006–TRTR–0014
Gulkana Village Council	Alaska		232,600		D2006–TRTR–0015
Hannahville Indian Community	Michigan	25,000			D2006–TRTR–0016
Houlton Band of Maliseet Indians	Maine			99,171	D2006–TRTR–0017
Hualapai Indian Tribe	Arizona	25,000			D2006–TRTR–0018
Iowa Tribe of Oklahoma	Oklahoma	25,000			D2006–TRTR–0019
Kalispel Tribe of Indians	Washington		167,547		D2006–TRTR–0020
Kaw Nation	Oklahoma	25,000			D2006–TRTR–0021
Lac du Flambeau Band of Lake Superior Chippewa.	Wisconsin	25,000			D2006–TRTR–0022
Leech Lake Band of Ojibwe	Minnesota	25,000			D2006–TRTR–0023
Lower Sioux Indian Community	Minnesota	25,000			D2006–TRTR–0024
Lummi Tribe of the Lummi Reservation	Washington		306,500		D2006–TRTR–0025
Menominee Indian Tribe of Wisconsin	Wisconsin			270,002	D2006–TRTR–0026
Narragansett Indian Tribe	Rhode Island	25,000			D2006–TRTR–0027
Northern Cheyenne	Montana		400,000		D2006–TRTR–0028
Oglala Sioux Tribe	South Dakota		327,869		D2006–TRTR–0029
Orutsaramiut Native Council	Alaska		105,193		D2006–TRTR–0030
Poarch Band of Creek Indians	Alabama			75,139	D2006–TRTR–0031
Pokagon Band of Potawatomi Indians	Michigan	25,000			D2006–TRTR–0032
Ponca Tribe Nebraska	Nebraska	25,000			D2006–TRTR–0033

FY 2006 TRIBAL TRANSIT GRANT RECIPIENTS—Continued

Tribe	State	Planning (in dollars)	Start-up (in dollars)	Ehancement (in dollars)	Project No.
Ponca Tribe of Oklahoma	Oklahoma		207,836		D2006–TRTR–0034
Prairie Band Potawatomi Nation	Kansas			360,000	D2006–TRTR–0035
Pueblo of Laguna-Shaa'srka Transit	New Mexico	25,000			D2006–TRTR–0036
Pueblo of Santa Ana	New Mexico	25,000			D2006–TRTR–0037
Quapaw Tribe of Okalahoma	Oklahoma	25,000			D2006–TRTR–0038
Quinault Tribe of the Quinault Reservation	Washington	25,000			D2006–TRTR–0039
Red Lake Band of Chippewa Indians	Minnesota			199,817	D2006–TRTR–0040
Saint Regis Mohawk Tribe	New York	25,000			D2006–TRTR–0041
Santee Sioux Nation	Nebraska	13,800			D2006–TRTR–0042
Seminole Nation	Oklahoma		145,000		D2006–TRTR–0043
Seneca Nation of Indians	New York	25,000			D2006–TRTR–0044
Skokomish Indian Tribe of the Skokomish	Washington	25,000			D2006–TRTR–0045
Snoquamile Tribe	Washington		274,169		D2006–TRTR–0046
Spirit Lake Tribe	North Dakota	25,000			D2006–TRTR–0047
Squaxin Island Tribe	Washington	25,000			D2006–TRTR–0048
Suquamish Tribe	Washington	25,000			D2006–TRTR–0049
Susanville Indian Rancheria	California		99,253		D2006–TRTR–0050
The Chickasaw Nation	Oklahoma			349,164	D2006–TRTR–0051
The Citizen Potawatomi Nation	Oklahoma			285,000	D2006–TRTR–0052
The Navajo Nation	Arizona			500,000	D2006–TRTR–0053
The Sac and Fox Nation	Kansas	25,000			D2006–TRTR–0054
The Shoalwater Bay Indian Tribe	Washington	24,797			D2006–TRTR–0055
The Sitka Tribe	Alaska			265,207	D2006–TRTR–0056
Upper Sioux Community	Minnesota	21,368			D2006–TRTR–0057
Wampanoag Tribe of Gay Head (Aquinnah)	Massachusetts	25,000			D2006–TRTR–0058
Washoe Tribe of Nevada and California	Nevada	25,000			D2006–TRTR–0059
White Mountain Apache Tribe	Arizona	25,000			D2006–TRTR–0060
Winnebago Tribe of Nebraska	Nebraska			457,580	D2006–TRTR–0061
Yavapai-Apache Nation	Arizona	25,000			D2006–TRTR–0062
Yurok Tribe	California		164,484		D2006–TRTR–0063
Total		834,965	3,168,681	3,916,354	
Total: $7,920,000.					

Issued in Washington, DC, this 29th day of March, 2007.

James S. Simpson,

Administrator.

Appendix A—FTA Regional Offices and Tribal Transit Liaisons

Region I—Massachusetts, Rhode Island, Connecticut, New Hampshire, Vermont and Maine
Richard H. Doyle, FTA Regional Administrator, Volpe National Transportation Systems Center, Kendall Square, 55 Broadway, Suite 920, Cambridge, MA 02142–1093, Phone: (617) 494–2055, Fax: (617) 494–2865
Regional Tribal Liaison: Judi Molloy
Region II—New York, New Jersey
Brigid Hynes-Cherin, FTA Regional Administrator, One Bowling Green, Room 429, New York, NY 10004–1415, Phone: (212) 668–2170, Fax: (212) 668–2136
Regional Tribal Liaison: Rebecca Reyes-Alicea
Region III—Pennsylvania, Maryland, Virginia, West Virginia, Delaware, Washington, DC
Herman Shipman, Acting FTA Regional Administrator, 1760 Market Street, Suite 500, Philadelphia, PA 19103–4124, Phone: (215) 656–7100, Fax: (215) 656–7260
Region IV—Georgia, North Carolina, South Carolina, Florida, Mississippi, Tennessee, Kentucky, Alabama, Puerto Rico, Virgin Islands
Yvette G. Taylor, FTA Regional Administrator, 61 Forsyth Street, SW., Suite 17T50, Atlanta, GA 30303, Phone: (404) 562–3500, Fax: (404) 562–3505
Regional Tribal Liaisons: Jamie Pfister and James Garland
Region V—Illinois, Indiana, Ohio, Wisconsin, Minnesota, Michigan
Marisol R. Simon, FTA Regional Administrator, 200 West Adams Street, Suite 320, Chicago, IL 60606–5232, Phone: (312) 353–2789, Fax: (312) 886–0351
Regional Tribal Liaisons: William Wheeler
Region VI—Texas, New Mexico, Louisiana, Arkansas, Oklahoma
Robert Patrick, FTA Regional Administrator, 819 Taylor Street, Room 8A36, Ft. Worth, TX 76102, Phone: (817) 978–0550, Fax: (817) 978–0575
Regional Tribal Liaison: Lynn Hayes
Region VII—Iowa, Nebraska, Kansas, Missouri
Mokhtee Ahmad, FTA Regional Administrator, 901 Locust Street, Suite 404, Kansas City, MO 64106, Phone: (816) 329–3920, Fax: (816) 329–3921
Regional Tribal Liaisons: Joni Roeseler and Cathy Monroe
Region VIII—Colorado, North Dakota, South Dakota, Montana, Wyoming, Utah
Letitia A. Thompson, Acting FTA Regional Administrator, 12300 West Dakota Avenue, Suite 310, Lakewood, CO 80228–2583, Phone: (720) 963–3300, Fax: (720) 963–3333
Regional Tribal Liaisons: Jennifer Stewart and David Beckhouse
Region IX—California, Arizona, Nevada, Hawaii, American Samoa, Guam
Leslie Rogers, FTA Regional Administrator, 201 Mission Street, Suite 1650, San Francisco, CA 94105–1831, Phone: (415) 744–3133, Fax: (415) 744–2726
Regional Tribal Liaison: Donna Turchie
Region X—Washington, Oregon, Idaho, Alaska
Richard Krochalis, FTA Regional Administrator, Jackson Federal Building, 915 Second Avenue, Suite 3142, Seattle, WA 98174–1002, Phone: (206) 220–7954, Fax: (206) 220–7959
Regional Tribal Liaisons: Bill Ramos and Annette Clothier

[FR Doc. E7–6192 Filed 4–3–07; 8:45 am]

BILLING CODE 4910–57–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[STB Finance Docket No. 34797]

New England Transrail, LLC, D/B/A Wilmington & Woburn Terminal Railway—Construction, Acquisition and Operation Exemption—in Wilmington and Woburn, MA

AGENCY: Surface Transportation Board, DOT.

ACTION: Notice of oral argument.

SUMMARY: The Surface Transportation Board will hold an oral argument on Thursday, April 19, 2007, at 10 a.m., at its offices in Washington, DC. The argument will explore what planned activities by the above-referenced petitioner would be part of rail transportation subject to the Board's jurisdiction. All current parties of record may participate, and New England Transrail, LLC (NET) is directed to participate.

DATES: Any current party of record in STB Finance Docket No. 34797 wishing to speak at the oral argument should file with the Board a written notice of intent to participate, and should identify a requested time allotment as soon as possible, but no later than April 6, 2007. The Board will issue a decision allocating times to the participants. Each participant should submit a written statement of its position on April 16, 2007.

ADDRESSES: All notices of intent to participate may be submitted either via the Board's e-filing format or in the traditional paper format. Any person using e-filing should comply with directions posted at the Board's *http://www.stb.dot.gov* Web site, at the ''E-FILING'' link. E-filers, please remember that formal filings must be submitted as a PDF document and, if available, in the original electronic document format (such as Word, Excel or WordPerfect). Any person submitting a filing in the traditional paper format should send an original and 10 copies of the filing to: Surface Transportation Board, Attn: STB Finance Docket No. 34797, 395 E Street, SW., Washington, DC 20423–0001.

FOR FURTHER INFORMATION, CONTACT: Joseph Dettmar, (202) 245–0395. [Assistance for the hearing impaired is available through the Federal Information Relay Service (FIRS) at: (800) 877–8339.]

SUPPLEMENTARY INFORMATION: On December 5, 2005, NET, a noncarrier, filed a petition for exemption to acquire, construct, and operate a rail line and related facilities in Wilmington and Woburn, MA. NET proposes to receive by truck at the site, and provide rail transportation for, a variety of commodities, including sand and gravel, plastic resins, liquids, municipal solid waste (MSW) and construction and demolition debris (C&D). NET explains that it would sort, grind, crush, aggregate, segregate, and/or bale all of the C&D and some of the MSW it receives before loading the materials onto rail cars or containers for rail shipment. NET asserts that all of its proposed activities and operations at the site would either constitute rail transportation, or would be integrally related to such transportation, and would therefore be subject to the Board's jurisdiction. A number of parties disagree, maintaining that NET's proposed activities involving C&D and MSW would not be part of rail transportation.

The Board will conduct an oral argument to further explore some of the issues raised by NET and the other interested parties. NET is directed to participate and other parties of record are encouraged to participate. Participants are asked to be prepared to respond to questions from the Board based on the record in this case, and, in addition, to discuss the following issues:

- Is it premature to issue a preliminary decision given the pending appeal in the United States Court of Appeals for the Third Circuit in the New York, Susquehanna and Western case [1] and the ongoing Environmental Protection Agency remedial investigation and feasibility study under the Superfund laws on the property on which NET proposes to operate the business at issue in this matter?
- What Federal statutes and regulations are applicable to facilities where C&D and MSW are handled and to what extent is their administration delegated to the states?
- Could the Board address the state environmental concerns associated with NET's proposal by conditioning any Board authorization of NET's proposal on NET permitting state officials to periodically inspect the facility? If so, could the Board provide for the suspension or revocation of NET's authorization on the recommendation of state officials based on an unsatisfactory inspection, provided that NET has some due process recourse to the Board?
- If the C&D and MSW activities proposed by NET are determined not to be part of rail transportation, what impact would such a decision have on this proposal and on the transloading of other commodities by railroads?
- In determining whether a facility is a rail transloading facility, must the activities that take place there be solely transportation activities?
- In determining whether NET's proposed activities would be part of rail transportation, would it be enough that an activity facilitates transportation, or must that activity be essential to the transportation?
- May a determination be based on the type of commodity involved? To what extent, if any, does it matter that the proposed facility would handle multiple commodities?
- Should C&D and MSW be considered differently from all other commodities and, if so, on what basis?
- What is the source of the materials other than C&D and MSW that NET proposes to transport? Where are those shipments destined? Would those commodities be segregated from C&D and MSW? How would they be segregated, loaded and unloaded?
- Would NET's proposed activities at the transload facility with respect to C&D and MSW add value to the materials, facilitate the disposal of the materials in a landfill or otherwise, or serve any purpose other than facilitating rail transport? If so, should that have an impact on our determination here?
- To what extent would NET's proposed handling of C&D and MSW be directed towards ensuring that the material would meet the requirements of the landfill, or other receiver, to which it would be transported?
- Does NET anticipate earning revenue as a result of any recycling activities, e.g., NET's proposed activities of inspection, sorting and reclaiming of reusable materials from the C&D and MSW at this facility?
- What is the background of each of the principals of NET? What is the extent of their prior and current involvement in (a) the railroad industry; (b) the trucking industry; (c) the MSW and C&D industries; and (d) environmental compliance issues? How was the NET project conceived?

Date of Oral argument. The oral argument will begin at 10 a.m. on Thursday, April 19, 2007, in the 1st floor hearing room at the Board's headquarters at 395 E Street, SW., in Washington, DC, and will continue until every person scheduled to speak has been heard.

Notice of Intent to Participate. Any party of record wishing to speak at the oral argument should file with the Board a written notice of intent to

[1] *New York, Susquehanna and Western Railway Corp.* v. *Jackson, New Jersey Meadowlands Commission et al.*, No. 05–4010, 2007 WL 576431 (D.N.J. Feb. 21, 2007), *appeal docketed*, No. 07–1675 (3d Cir. Mar. 16, 2007).

participate, and should indicate a requested time allotment, as soon as possible, but no later than April 6, 2007.

Board Releases and Live Audio Available Via the Internet. Decisions and notices of the Board, including this notice, are available on the Board's Web site at *http://www.stb.dot.gov*. This oral argument will be available on the Board's Web site by live audio streaming. To access the oral argument, click on the ''Live Audio'' link under ''Information Center'' at the left side of the home page beginning at 10 a.m. on April 19, 2007.

This action will not significantly affect either the quality of the human environment or the conservation of energy resources.

Dated: March 29, 2007.

Vernon A. Williams,

Secretary.

[FR Doc. E7–6214 Filed 4–3–07; 8:45 am]

BILLING CODE 4915–01–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[STB Docket No. AB–6 (Sub-No. 449X)]

BNSF Railway Company—Abandonment Exemption—in Swift County, MN

BNSF Railway Company (BNSF) has filed a notice of exemption under 49 CFR part 1152 subpart F—*Exempt Abandonments* to abandon a rail line between Engineering Stations 0 + 00 and 28 + 61, near Appleton, in Swift County, MN, a distance of 0.54 miles. The line traverses United States Postal Service Zip Code 56208.

BNSF has certified that: (1) No local traffic has moved over the line for at least 2 years; (2) any overhead traffic on the line can be rerouted; (3) no formal complaint filed by a user of rail service on the line (or by a state or local government entity acting on behalf of such user) regarding cessation of service over the line either is pending with the Surface Transportation Board or with any U.S. District Court or has been decided in favor of complainant within the 2-year period; and (4) the requirements of 49 CFR 1105.7 (environmental report), 49 CFR 1105.8 (historic report), 49 CFR 1105.11 (transmittal letter), 49 CFR 1105.12 (newspaper publication), and 49 CFR 1152.50(d)(l) (notice to governmental agencies) have been met.

As a condition to this exemption, any employees adversely affected by the abandonment shall be protected under *Oregon Short Line R. Co.—Abandonment—Goshen*, 360 I.C.C. 91 (1979). To address whether this condition adequately protects affected employees, a petition for partial revocation under 49 U.S.C. 10502(d) must be filed.

Provided no formal expression of intent to file an offer of financial assistance (OFA) has been received, this exemption will be effective on May 4, 2007, unless stayed pending reconsideration. Petitions to stay that do not involve environmental issues,[1] formal expressions of intent to file an OFA under 49 CFR 1152.27(c)(2),[2] and trail use/rail banking requests under 49 CFR 1152.29 must be filed by April 16, 2007. Petitions to reopen or requests for public use conditions under 49 CFR 1152.28 must be filed by April 24, 2007, with: Surface Transportation Board, 395 E Street, SW., Washington, DC 20423–0001.

A copy of any petition filed with the Board should be sent to BNSF's representative: Sidney L. Strickland, Jr., 3050 K Street, NW., Suite 101, Washington, DC 20007.

If the verified notice contains false or misleading information, the exemption is void *ab initio*.

BNSF has filed environmental and historic reports which address the effects, if any, of the abandonment on the environment and historic resources. SEA will issue an environmental assessment (EA) by April 9, 2007. Interested persons may obtain a copy of the EA by writing to SEA (Room 1100, Surface Transportation Board, Washington, DC 20423–0001) or by calling SEA, at (202) 245–0305. [Assistance for the hearing impaired is available through the Federal Information Relay Service (FIRS) at 1–800–877–8339.] Comments on environmental and historic preservation matters must be filed within 15 days after the EA becomes available to the public.

Environmental, historic preservation, public use, or trail use/rail banking conditions will be imposed, where appropriate, in a subsequent decision.

Pursuant to the provisions of 49 CFR 1152.29(e)(2), BNSF shall file a notice of consummation with the Board to signify that it has exercised the authority granted and fully abandoned the line. If consummation has not been effected by BNSF's filing of a notice of consummation by April 4, 2008, and there are no legal or regulatory barriers to consummation, the authority to abandon will automatically expire.

Board decisions and notices are available on our Web site at *http://www.stb.dot.gov*.

Decided: March 23, 2007.

By the Board, Joseph H. Dettmar, Acting Director, Office of Proceedings.

Vernon A. Williams,

Secretary.

[FR Doc. E7–5784 Filed 4–3–07; 8:45 am]

BILLING CODE 4915–01–P

[1] The Board will grant a stay if an informed decision on environmental issues (whether raised by a party or by the Board's Section of Environmental Analysis (SEA) in its independent investigation) cannot be made before the exemption's effective date. *See Exemption of Out-of-Service Rail Lines*, 5 I.C.C.2d 377 (1989). Any request for a stay should be filed as soon as possible so that the Board may take appropriate action before the exemption's effective date.

[2] Each OFA must be accompanied by the filing fee which is currently set at $1,300. *See* 49 CFR 1002.2(f)(25).

DEPARTMENT OF THE TREASURY

Office of the Assistant Secretary for International Affairs; Survey of Foreign Ownership of U.S. Securities

AGENCY: Departmental Offices, Department of the Treasury.

ACTION: Notice of reporting requirements.

SUMMARY: By this Notice, the Department of the Treasury is informing the public that it is conducting a mandatory survey of foreign ownership of U.S. securities as of June 30, 2007. This Notice constitutes legal notification to all United States persons (defined below) who meet the reporting requirements set forth in this Notice that they must respond to, and comply with, this survey. Additional copies of the reporting forms SHLA (2007) and instructions may be printed from the Internet at: *http://www.treas.gov/tic/forms-sh.html.*

Definition: A U.S. person is any individual, branch, partnership, associated group, association, estate, trust, corporation, or other organization (whether or not organized under the laws of any State), and any government (including a foreign government, the United States Government, a state, provincial, or local government, and any agency, corporation, financial institution, or other entity or instrumentality thereof, including a government-sponsored agency), who resides in the United States or is subject to the jurisdiction of the United States.

Who Must Report: The panel for this survey is based upon the level of foreign holdings of U.S. securities reported on the June 2004 benchmark survey of foreign holdings of U.S. securities, and will consist mostly of the largest reporters on that survey. Entities

required to report will be contacted individually by the Federal Reserve Bank of New York. Entities not contacted by the Federal Reserve Bank of New York have no reporting responsibilities.

What to Report: This report will collect information on foreign resident holdings of U.S. securities, including equities, short-term debt securities (including selected money market instruments), and long-term debt securities.

How to Report: Copies of the survey forms and instructions, which contain complete information on reporting procedures and definitions, can be obtained by contacting the survey staff of the Federal Reserve Bank of New York at (212) 720–6300, e-mail: *SHLA.help@ny.frb.org.* The mailing address is: Federal Reserve Bank of New York, Statistics Function, 4th Floor, 33 Liberty Street, New York, NY 10045–0001. Inquiries can also be made to Mr. William L. Griever, Federal Reserve Board of Governors, at (202) 452–2924, e-mail: *william.l.griever@frb.gov*; or to Dwight Wolkow at (202) 622–1276, e-mail: *wolkowd@do.treas.gov.*

When to Report: Data should be submitted to the Federal Reserve Bank of New York, acting as fiscal agent for the Department of the Treasury, by August 31, 2007.

Paperwork Reduction Act Notice: This data collection has been approved by the Office of Management and Budget (OMB) in accordance with the Paperwork Reduction Act and assigned control number 1505–0123. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid control number assigned by OMB. The estimated average annual burden associated with this collection of information is 486 hours per report for the largest custodians of securities, and 110 hours per report for the largest issuers of securities that have data to report and are not custodians. Comments concerning the accuracy of this burden estimate and suggestions for reducing this burden should be directed to the Department of the Treasury, Office of International Affairs, Attention Administrator, International Portfolio Investment Data Reporting Systems, Room 5422, Washington, DC 20220, and to OMB, Attention Desk Officer for the Department of the Treasury, Office of Information and Regulatory Affairs, Washington, DC 20503.

Dwight Wolkow,

Administrator, International Portfolio Investment Data Reporting Systems.

[FR Doc. E7–6196 Filed 4–3–07; 8:45 am]

BILLING CODE 4811–42–P

DEPARTMENT OF THE TREASURY

No FEAR Act Notice

Summary: The Department of the Treasury is publishing its Notification and Federal Employee Antidiscrimination and Retaliation Notice (''No FEAR Notice'') to provide information to current employees, former employees and applicants for Treasury employment of their rights and protections available under Federal antidiscrimination, whistleblower protection and retaliation laws. The Office of Personnel Management has issued a final rule allowing an agency to ''meet its paper and electronic notice obligations to former employees and applicants by publishing an initial notice in the **Federal Register**.'' 5 CFR 724.202. Treasury's No FEAR Act Notice is available on Treasury's Web site at *http://www.treas.gov/nofearact/.*

For Further Information Contact: Mariam G. Harvey, Director, Office of Equal Opportunity and Diversity, Department of the Treasury, 1750 Pennsylvania Avenue, NW., Room 8157D, Washington, DC 20220; (202) 622–1160.

No Fear Act Notice

On May 15, 2002, Congress enacted the ''Notification and Federal Employee Antidiscrimination and Retaliation Act of 2002,'' which is now known as the No FEAR Act. One purpose of the Act is to ''require that Federal agencies be accountable for violations of antidiscrimination and whistleblower protection laws.'' Pub. L. 107–174, Summary. In support of this purpose, Congress found that ''agencies cannot be run effectively if those agencies practice or tolerate discrimination.'' Pub. L. 107–174, Title I, General Provisions, section 101(1). The Act also requires this agency to provide this notice to Federal employees, former Federal employees and applicants for Federal employment to inform you of the rights and protections available to you under Federal antidiscrimination and whistleblower protection laws.

Antidiscrimination Laws

A Federal agency cannot discriminate against an employee or applicant with respect to the terms, conditions or privileges of employment on the basis of race, color, religion, sex, national origin, age, disability, marital status or political affiliation. Discrimination on these bases is prohibited by one or more of the following statutes: 5 U.S.C. 2302(b)(1), 29 U.S.C. 206(d), 29 U.S.C. 631, 29 U.S.C. 633a, 29 U.S.C. 791 and 42 U.S.C. 2000e-16. If you believe that you have been the victim of unlawful discrimination on the basis of race, color, religion, sex, national origin or disability, you must contact an Equal Employment Opportunity (EEO) counselor within 45 calendar days of the alleged discriminatory action, or, in the case of a personnel action, within 45 calendar days of the effective date of the action, before you can file a formal complaint of discrimination with your agency. See, e.g. 29 CFR part 1614. If you believe that you have been the victim of unlawful discrimination on the basis of age, you must either contact an EEO counselor as noted above or give notice of intent to sue to the Equal Employment Opportunity Commission (EEOC) within 180 calendar days of the alleged discriminatory action. If you are alleging discrimination based on marital status or political affiliation, you may file a written complaint with the U.S. Office of Special Counsel (OSC) (see contact information below). In the alternative (or in some cases, in addition), you may pursue a discrimination complaint by filing a grievance through your agency's administrative or negotiated grievance procedures, if such procedures apply and are available.

Whistleblower Protection Laws

A Federal employee with authority to take, direct others to take, recommend or approve any personnel action must not use that authority to take or fail to take, or threaten to take or fail to take, a personnel action against an employee or applicant because of disclosure of information by that individual that is reasonably believed to evidence violations of law, rule or regulation; gross mismanagement; gross waste of funds; an abuse of authority; or a substantial and specific danger to public health or safety, unless disclosure of such information is specifically prohibited by law and such information is specifically required by Executive order to be kept secret in the interest of national defense or the conduct of foreign affairs. Retaliation against an employee or applicant for making a protected disclosure is prohibited by 5 U.S.C. 2302(b)(8). If you believe that you have been the victim of whistleblower retaliation, you may file a written complaint (Form OSC–11) with the U.S.

Office of Special Counsel at 1730 M Street NW., Suite 218, Washington, DC 20036–4505 or online through the OSC Web site—*http://www.osc.gov.*

Retaliation for Engaging in Protected Activity

A Federal agency cannot retaliate against an employee or applicant because that individual exercises his or her rights under any of the Federal antidiscrimination or whistleblower protection laws listed above. If you believe that you are the victim of retaliation for engaging in protected activity, you must follow, as appropriate, the procedures described in the Antidiscrimination Laws and Whistleblower Protection Laws sections or, if applicable, the administrative or negotiated grievance procedures in order to pursue any legal remedy.

Disciplinary Actions

Under the existing laws, each agency retains the right, where appropriate, to discipline a Federal employee for conduct that is inconsistent with Federal Antidiscrimination and Whistleblower Protection Laws up to and including removal. If OSC has initiated an investigation under 5 U.S.C. 1214, however, according to 5 U.S.C. 1214(f), agencies must seek approval from the Special Counsel to discipline employees for, among other activities, engaging in prohibited retaliation. Nothing in the No FEAR Act alters existing laws or permits an agency to take unfounded disciplinary action against a Federal employee or to violate the procedural rights of a Federal employee who has been accused of discrimination.

Additional Information

For further information regarding the No FEAR Act regulations, refer to 5 CFR part 724, or contact the Office of Equal Opportunity and Diversity, 1750 Pennsylvania Avenue, NW., Suite 8157D, Washington, DC 20220, (202) 622–1160. Additional information regarding Federal antidiscrimination, whistleblower protection and retaliation laws can be found at the EEOC Web site—*http://www.eeoc.gov* and the OSC Web site—*http://www.osc.gov.*

Existing Rights Unchanged

Pursuant to section 205 of the No FEAR Act, neither the Act nor this notice creates, expands or reduces any rights otherwise available to any employee, former employee or applicant under the laws of the United States, including the provisions of law specified in 5 U.S.C. 2302(d).

U.S. Department of the Treasury.

Dated: March 28, 2007.

Wesley T. Foster,

Acting Assistant Secretary for Management.

[FR Doc. E7–6223 Filed 4–3–07; 8:45 am]

BILLING CODE 4811–42–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Privacy Act of 1974: Computer Matching Program

AGENCY: Internal Revenue Service, Treasury.

ACTION: Notice of Matching Program.

SUMMARY: Pursuant to the Privacy Act of 1974, as amended, and the Office of Management and Budget (OMB) Guidelines on the Conduct of Matching Programs, notice is hereby given of the conduct of the Internal Revenue Service matching of systems of records Treasury/IRS 36.003 General Personnel and Payroll and Treasury .010 Telephone Call Detail Records.

DATES: *Effective Date:* This notice will be effective May 4, 2007.

ADDRESSES: Inquiries may be mailed to ACIO, Enterprise Networks; OS:CIO:EN 1111 Constiution Avenue, NW., Washington DC, 20224. Mailstop 3137.

FOR FURTHER INFORMATION CONTACT: Brenda N. Carroll, Project Manager, Telecommunications Asset Tool (TAT), OS:CIO:EN:P:V, Internal Revenue Service, (202) 283–4680.

SUPPLEMENTARY INFORMATION: The matching process is needed for the Internal Revenue Service (IRS), Enterprise Networks, Waste, Fraud, and Abuse initiative to automatically match long distance telephone and calling card call detail records/data to employee making the call(s) and match to the manager of that respective employee by using the Telecommunications Asset Tool (TAT), Corporate Authoritative Directory Services (CADS), and the Calling Card Ordering System (CCOS). Members of the public desiring specific information concerning an ongoing matching activity may request a copy of the applicable computer matching agreement at the address provided above.

Name of Source Agency: Internal Revenue Service.

Name of Recipient Agency: Internal Revenue Service.

Purpose: The purpose of this program is to prevent or reduce waste, fraud, and abuse while protecting the privacy interest of the subjects of the match.

Authority: 5 CFR part 2635, Standards of Ethical Conduct for Employees of the Executive Branch; 5 CFR part 3101, Supplemental Standards of Ethical Conduct for Employees of the Treasury Department Treasury Supplemental Standards (§§ 3101.101–3191, 107, the Treasury Employee Rules of Conduct).

In the past several years the Service has been increasingly challenged to ensure that all resources are used as efficiently as possible. Telecommunications expenditures are one of the largest items in the Service's budget and continue to be an area warranting increased scrutiny due to the steady and dramatic rise in telecommunications usage and cost. On September 25, 2001, in partnership with the National Treasury Employees Union (NTEU), the Service entered into an agreement to implement a new system for reviewing telecommunications usage.

A major purpose of the TAT is to provide a system of checks and balances that directly address the integrity of the data. The call detail data has been derived from Sprint billing data received monthly and used to build the call detail database. The new agency-wide TAT review process will concentrate on two areas: (1) Potential waste, fraud, and abuse of telecommunications resources; and (2) lost personnel productivity based on excessive time devoted to personal telephone calls. TAT provides data on 100% of call detail records, including long distance telephone calls and calling card calls. TAT is the tool for managing telecommunications expenditures and for identifying waste, fraud, and abuse. Additionally, managers can request ad hoc reports detailing calls from office telephones or calling cards if the manager suspects potential problems related to these services. The IRS is the only Federal agency that provides and uses the data.

Categories of individuals covered in the match: All IRS employees and IRS contractors who have a security clearance and are assigned a Standard Employee Identifier (SEID).

Categories of records covered in the match: Personnel/Payroll and Telephone Call Detail records from the following Privacy Act systems of records:

A. Treasury/IRS 36.003 General Personnel and Payroll Data

CADS data to be used in the matching program: Standard Employee Identifier (SEID), Employee Name, Manager Name, Organizational Symbols, Building/Room Number, Business Office Address, Employee Telephone Number.

B. Treasury/IRS 36.003 General Personnel and Payroll Data

CCOS data to be used in the matching program: Standard Employee Identifier (SEID), Employee Name, Manager Name, Organizational Symbols, Building/Room Number, Business Office Address, Calling Card Number.

C. Treasury .010 Telephone Call Detail Records

TAT data to be used in the matching program: Date, Time, Originating Telephone Number, Originating Access, Terminating Telephone Number, Terminating City/State, Terminating Access, Minutes, Conference Call Cancellation Charge, Calling Card Number, Tax and Total Cost.

The telephone number or calling card data from the TAT process will be matched with CADS or CCOS database to identify the employee assigned to the respective telephone number/calling card and identify the manager to whom the employee is assigned. Once the manager is identified, the respective/applicable call detail report(s) are generated.

Beginning and completion dates: The matches are conducted on an ongoing basis in accordance with the terms of the computer matching agreement in effect between the parties as approved by the Treasury Data Integrity Board. The term of this agreement is expected to cover the 18-month period beginning March 1, 2007 and ending August 31, 2008.

Ninety days prior to expiration of the agreement, the parties to the agreement may request a 12-month extension in accordance with 5 U.S.C. 552a(o).

Dated: March 28, 2007.

Wesley T. Foster,

Acting Assistant Secretary for Management.

[FR Doc. E7–6238 Filed 4–3–07; 8:45 am]

BILLING CODE 4830–01–P

Corrections

Federal Register

Vol. 72, No. 64

Wednesday, April 4, 2007

This section of the FEDERAL REGISTER contains editorial corrections of previously published Presidential, Rule, Proposed Rule, and Notice documents. These corrections are prepared by the Office of the Federal Register. Agency prepared corrections are issued as signed documents and appear in the appropriate document categories elsewhere in the issue.

DEPARTMENT OF DEFENSE

Department of the Army

Draft Environmental Impact Statement for the Renewal of Special Use Permit for Military Activities on the De Soto National Forest and Implementation of Installation Mission Support Activities at Camp Shelby, MS

Correction

In notice document 07–1571 beginning on page 15120, in the issue of Friday, March 30, 2007, make the following correction:

On page 15120, in the third column, under the **FOR FURTHER INFORMATION CONTACT** heading, in the last line, ''Program at (610) 313–6228'' should read ''Programs at (601) 313–6228''.

[FR Doc. C7–1571 Filed 4–3–07; 8:45 am]

BILLING CODE 1505–01–D

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

Intent To Prepare a Draft Environmental Impact Report/ Environmental Impact Statement for the Buena Vista Lagoon Restoration Project, San Diego County, CA

Correction

In notice document 07–1373 beginning on page 13301 in the issue of Wednesday, March 21, 2007, make the following corrections:

1. On page 13301, in the second column, under the **DATES** heading, in the third line, ''DETR'' should read ''DEIR''.

2. On page 13302, in the second column, in the eighth line from the bottom of the column, ''meting'' should read ''meeting''.

3. On the same page, in the third column, in the first line, ''is'' should read ''us''.

[FR Doc. C7–1373 Filed 4–3–07; 8:45 am]

BILLING CODE 1505–01–D

DEPARTMENT OF STATE

[Delegation of Authority No. 296]

Delegation by the Under Secretary of State for Political Affairs to the Assistant Secretary of State for Educational and Cultural Affairs of the Functions Relating to Emergency Import Restrictions on Iraqi Cultural Antiquities

Correction

In notice document E7–3011 appearing on page 8054 in the issue of Thursday, February 22, 2007, make the following correction:

In the third column, in sixth line from the bottom of the document, ''December 22, 2007'' should read ''December 22, 2006''.

[FR Doc. Z7–3011 Filed 4–3–07; 8:45 am]

BILLING CODE 1505–01–D

Federal Register

Wednesday,
April 4, 2007

Part II

Department of Energy

Federal Energy Regulatory Commission

18 CFR Part 40

Mandatory Reliability Standards for the Bulk-Power System; Final Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM06–16–000; Order No. 693]

Mandatory Reliability Standards for the Bulk-Power System

Issued March 16, 2007.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Pursuant to section 215 of the Federal Power Act (FPA), the Commission approves 83 of 107 proposed Reliability Standards, six of the eight proposed regional differences, and the Glossary of Terms Used in Reliability Standards developed by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards. Those Reliability Standards meet the requirements of section 215 of the FPA and Part 39 of the Commission's regulations. However, although we believe it is in the public interest to make these Reliability Standards mandatory and enforceable, we also find that much work remains to be done. Specifically, we believe that many of these Reliability Standards require significant improvement to address, among other things, the recommendations of the Blackout Report. Therefore, pursuant to section 215(d)(5), we require the ERO to submit significant improvements to 56 of the 83 Reliability Standards that are being approved as mandatory and enforceable. The remaining 24 Reliability Standards will remain pending at the Commission until further information is provided.

The Final Rule adds a new part to the Commission's regulations, which states that this part applies to all users, owners and operators of the Bulk-Power System within the United States (other than Alaska or Hawaii) and requires that each Reliability Standard identify the subset of users, owners and operators to which that particular Reliability Standard applies. The new regulations also require that each Reliability Standard that is approved by the Commission will be maintained on the ERO's Internet Web site for public inspection.

EFFECTIVE DATE: This rule will become effective June 4, 2007.

FOR FURTHER INFORMATION CONTACT: Jonathan First (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8529.

Paul Silverman (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8683.

Robert Snow (Technical Information), Office of Energy Markets and Reliability, Division of Reliability, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6716.

Kumar Agarwal (Technical Information), Office of Energy Markets and Reliability, Division of Policy Analysis and Rulemaking, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8923.

SUPPLEMENTARY INFORMATION: Before Commissioners: Joseph T. Kelliher, Chairman; Suedeen G. Kelly; Marc Spitzer; Philip D. Moeller; and Jon Wellinghoff.

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I. Introduction

1. Pursuant to section 215 of the Federal Power Act (FPA), the Commission approves 83 of 107 proposed Reliability Standards, six of the eight proposed regional differences, and the Glossary of Terms Used in Reliability Standards (glossary) developed by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards. Those Reliability Standards meet the requirements of section 215 of the FPA and Part 39 of the Commission's regulations. However, although we believe it is in the public interest to make these Reliability Standards mandatory and enforceable, we also find that much work remains to be done. Specifically, we believe that many of these Reliability Standards require significant improvement to address, among other things, the recommendations of the Blackout Report.[1] Therefore, pursuant to section 215(d)(5), we require the ERO to submit significant improvements to 56 of the 83 Reliability Standards that are being approved as mandatory and enforceable. The remaining 24 Reliability Standards will remain pending at the Commission until further information is provided.

2. The Final Rule adds a new part to the Commission's regulations, which states that this part applies to all users, owners and operators of the Bulk-Power System within the United States (other than Alaska or Hawaii) and requires that each Reliability Standard identify the subset of users, owners and operators to which that particular Reliability Standard applies. The new regulations also require that each Reliability Standard that is approved by the Commission will be maintained on the ERO's Internet Web site for public inspection.

A. Background

1. EPAct 2005 and Order No. 672

3. On August 8, 2005, the Electricity Modernization Act of 2005, which is Title XII, Subtitle A, of the Energy Policy Act of 2005 (EPAct 2005), was enacted into law.[2] EPAct 2005 adds a new section 215 to the FPA, which requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight or the Commission can independently enforce Reliability Standards.[3]

4. On February 3, 2006, the Commission issued Order No. 672, implementing section 215 of the FPA.[4] Pursuant to Order No. 672, the Commission certified one organization, NERC, as the ERO.[5] The ERO is required to develop Reliability Standards, which are subject to Commission review and approval.[6] The Reliability Standards will apply to users, owners and operators of the Bulk-Power System, as set forth in each Reliability Standard.

5. Section 215(d)(2) of the FPA and the Commission's regulations provide that the Commission may approve a proposed Reliability Standard if it determines that the proposal is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable.[7] According to this guidance, a Reliability Standard must provide for the Reliable Operation of Bulk-Power System facilities and may impose a requirement on any user, owner or operator of such facilities. It must be designed to achieve a specified

[1] U.S.-Canada Power System Outage Task Force, Final Report on the August 14 Blackout in the United States and Canada: Causes and Recommendations (April 2004) (Blackout Report). The Blackout Report is available on the Internet at *http://www.ferc.gov/cust-protect/moi/blackout.asp.*

[2] Energy Policy Act of 2005, Pub. L. No 109–58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005), *to be codified* at 16 U.S.C. 824o.

[3] 16 U.S.C. 824o(e)(3).

[4] *Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards,* Order No. 672, 71 FR 8662 (February 17, 2006), FERC Stats. & Regs. ¶ 31,204 (2006), *order on reh'g,* Order No. 672–A, 71 FR 19814 (April 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006).

[5] *North American Electric Reliability Corp.,* 116 FERC ¶ 61,062 (*ERO Certification Order*), *order on reh'g & compliance,* 117 FERC ¶ 61,126 (*ERO Rehearing Order*) (2006), *order on compliance,* 118 FERC ¶ 61,030 (2007) (*January 2007 Compliance Order*).

[6] Section 215(a)(3) of the FPA defines the term Reliability Standard to mean ''a requirement, approved by the Commission under this section, to provide for reliable operation of the Bulk-Power System. This term includes requirements for the operation of existing Bulk-Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for the reliable operation of the Bulk-Power System, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.'' 16 U.S.C. 824o(a)(3).

[7] Order No. 672 at P 262, 321–37.

reliability goal and must contain a technically sound means to achieve this goal. The Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. The possible consequences for violating a Reliability Standard should be clear and understandable to those who must comply. There should be clear criteria for whether an entity is in compliance with a Reliability Standard. While a Reliability Standard does not necessarily need to reflect the optimal method for achieving its reliability goal, a Reliability Standard should achieve its reliability goal effectively and efficiently. A Reliability Standard must do more than simply reflect stakeholder agreement or consensus around the ''lowest common denominator.'' It is important that the Reliability Standards developed through any consensus process be sufficient to adequately protect Bulk-Power System reliability.[8]

6. A Reliability Standard may take into account the size of the entity that must comply and the costs of implementation. A Reliability Standard should be a single standard that applies across the North American Bulk-Power System to the maximum extent this is achievable taking into account physical differences in grid characteristics and regional Reliability Standards that result in more stringent practices. It can also account for regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard. Finally, a Reliability Standard should have no undue negative effect on competition.[9]

7. Order No. 672 directs the ERO to explain how the factors the Commission identified are satisfied and how the ERO balances any conflicting factors when seeking approval of a proposed Reliability Standard.[10]

8. Pursuant to section 215(d)(2) of the FPA and § 39.5(c) of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard or to a Regional Entity organized on an Interconnection-wide basis with respect to a proposed Reliability Standard or a proposed modification to a Reliability Standard to be applicable within that Interconnection. However, the Commission will not defer to the ERO or to such a Regional Entity with respect to the effect of a proposed Reliability Standard or proposed modification to a Reliability Standard on competition.[11]

9. The Commission's regulations require the ERO to file with the Commission each new or modified Reliability Standard that it proposes to be made effective under section 215 of the FPA. The filing must include a concise statement of the basis and purpose of the proposed Reliability Standard, a summary of the Reliability Standard development proceedings conducted by either the ERO or Regional Entity, together with a summary of the ERO's Reliability Standard review proceedings, and a demonstration that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[12]

10. Where a Reliability Standard requires significant improvement, but is otherwise enforceable, the Commission approves the Reliability Standard. In addition, as a distinct action under the statute, the Commission directs the ERO to modify such a Reliability Standard, pursuant to section 215(d)(5) of the FPA, to address the identified issues or concerns. This approach will allow the proposed Reliability Standard to be enforceable while the ERO develops any required modifications.

11. The Commission will remand to the ERO for further consideration a proposed new or modified Reliability Standard that the Commission disapproves in whole or in part.[13] When remanding a Reliability Standard to the ERO, the Commission may order a deadline by which the ERO must submit a proposed or modified Reliability Standard.

2. NERC Petition for Approval of Reliability Standards

12. On April 4, 2006, as modified on August 28, 2006, NERC submitted to the Commission a petition seeking approval of the 107 proposed Reliability Standards that are the subject of this Final Rule.[14] According to NERC, the 107 proposed Reliability Standards collectively define overall acceptable performance with regard to operation, planning and design of the North American Bulk-Power System. Seven of these Reliability Standards specifically incorporate one or more ''regional differences'' (which can include an exemption from a Reliability Standard) for a particular region or subregion, resulting in eight regional differences. NERC stated that it simultaneously filed the proposed Reliability Standards with governmental authorities in Canada. The Commission addresses these proposed Reliability Standards in this rulemaking proceeding.[15]

13. On November 15, 2006, NERC filed 20 revised proposed Reliability Standards and three new proposed Reliability Standards for Commission approval. The 20 revised Reliability Standards primarily provided additional Measures and Levels of Non-Compliance, but did not add or revise any existing Requirements to these Reliability Standards. NERC requested that the 20 revised proposed Reliability Standards be included as part of the Final Rule issued by the Commission in this docket. The proposed new Reliability Standards, FAC–010–1, FAC–011–1, and FAC–014–1, will be addressed in a separate rulemaking proceeding in Docket No. RM07–3–000.

14. On December 1, 2006, NERC submitted in Docket No. RM06–16–000 an informational filing entitled ''NERC's Reliability Standards Development Plan: 2007—2009'' (Work Plan). NERC stated it was submitting the Work Plan to inform the Commission of NERC's program to improve the Reliability Standards that currently are the subject of the Commission's rulemaking proceeding.

3. Staff Preliminary Assessment and Commission NOPR

15. On May 11, 2006, Commission staff issued a ''Staff Preliminary Assessment of the North American Electric Reliability Council's Proposed Mandatory Reliability Standards'' (Staff Preliminary Assessment). The Staff Preliminary Assessment identifies staff's observations and concerns regarding NERC's then-current voluntary Reliability Standards. The Staff Preliminary Assessment describes issues common to a number of proposed Reliability Standards. It reviews and identifies issues regarding each individual Reliability Standard but did not make specific recommendations regarding the appropriate Commission action on a particular proposal.

16. Comments on the Staff Preliminary Assessment were due by June 26, 2006. Approximately 50 entities filed comments in response to

[8] *Id.* at P 329.

[9] *Id.* at P 332.

[10] *Id.* at P 337.

[11] 18 CFR 39.5(c)(1), (3).

[12] 18 CFR 39.5(a).

[13] 18 CFR 39.5(e).

[14] The filed proposed Reliability Standards are not attached to the Final Rule but are available on the Commission's eLibrary document retrieval system in Docket No. RM06–16–000 and are available on the ERO's Web site, *http://www.nerc.com/filez/nerc_filings_ferc.html.*

[15] Eight proposed Reliability Standards submitted in the August 29, 2006 filing that relate to cyber security, Reliability Standards CIP–002 through CIP–009, will be addressed in a separate rulemaking proceeding in Docket No. RM06–22–000.

the Staff Preliminary Assessment. In addition, on July 6, 2006, the Commission held a technical conference to discuss NERC's proposed Reliability Standards, the Staff Preliminary Assessment, the comments and other related issues.

4. Notice of Proposed Rulemaking

17. The Commission issued the NOPR on October 20, 2006, and required that comments be filed within 60 days after publication in the **Federal Register**, or January 2, 2007.[16] The Commission granted the request of several commenters to extend the comment date to January 3, 2007. Several late-filed comments were filed. The Commission will accept these late-filed comments. A list of commenters appears in Appendix A.

18. On November 27, 2006, the Commission issued a notice on the 20 revised Reliability Standards filed by NERC on November 15, 2006. In the notice, the Commission explained that, because of their close relationship with Reliability Standards dealt with in the October 20, 2006 NOPR, the Commission would address these 20 revised Reliability Standards in this proceeding.[17] The notice provided an opportunity to comment on the revised Reliability Standards, with a comment due date of January 3, 2007.

19. The Commission issued a notice on NERC's Work Plan on December 8, 2006. While the Commission sought public comment on NERC's filing because it was informative on the prioritization of modifying Reliability Standards raised in the NOPR, the notice emphasized that the Work Plan was filed for informational purposes and NERC stated that it is not requesting Commission action on the Work Plan.

20. On February 6, 2007, NERC submitted a request for leave to file supplemental information, and included a revised version of the NERC Statement of Compliance Registry Criteria (Revision 3). NERC noted that it had submitted with its NOPR comments an earlier version of the same document.[18]

II. Discussion

A. Overview

1. The Commission's Underlying Approach To Review and Disposition of the Proposed Standards

21. In this Final Rule, the Commission takes the important step of approving the first set of mandatory and enforceable Reliability Standards within the United States in accordance with the provisions of new section 215 of the FPA. The Commission's action herein marks the official departure from reliance on the electric utility industry's voluntary compliance with Reliability Standards adopted by NERC and the regional reliability councils and the transition to the mandatory, enforceable Reliability Standards under the Commission's ultimate oversight through the ERO and, eventually, the Regional Entities, as directed by Congress. As we discuss more fully below, in deciding whether to approve, approve and direct modifications, or remand each of the proposed Reliability Standards in this Final Rule, our overall approach has been one of carefully balancing the need for practicality during the time of transition with the imperatives of section 215 of the FPA and Order No. 672, and other considerations.

22. In addition, our action today is informed by the August 14, 2003 blackout which affected significant portions of the Midwest and Northeast United States and Ontario, Canada and impacted an estimated 50 million people and 61,800 megawatts of electric load. As noted in the NOPR, a joint United States-Canada task force found that the blackout was caused by several entities violating NERC's then-effective policies and Reliability Standards.[19] Those violations directly contributed to the loss of a significant amount of electric load. The joint task force identified both the need for legislation to make Reliability Standards mandatory and enforceable with penalties for noncompliance, as well as particular Reliability Standards that needed corrections to make them more effective in preventing blackouts. Indeed, the August 2003 blackout and the recommendations of the joint task force helped foster enactment of EPAct 2005 and new section 215 of the FPA.

2. Mandates of Section 215 of the FPA

23. The imperatives of section 215 of the FPA address not only the protection of the reliability of the Bulk-Power System but also the reliability roles of the Commission, the ERO, the Regional Entities, and the owners, users and operators of the Bulk-Power System.[20] First, section 215 specifies that the ERO is to develop and enforce a comprehensive set of Reliability Standards subject to Commission review. Section 215 explains that a Reliability Standard is a requirement approved by the Commission that is intended to provide for the Reliable Operation of the Bulk-Power System. Such requirement may pertain to the operation of existing Bulk-Power System facilities, including cybersecurity protection, or it may pertain to the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the Bulk-Power System.[21]

24. Second, the reliability mandate of section 215 of the FPA addresses not only the comprehensive maintenance of the reliable operation of each of the elements of the Bulk-Power System, it also contemplates the prevention of incidents, acts and events that would interfere with the reliable operation of the Bulk-Power System. Further, section 215 seeks to prevent an instability, an uncontrolled separation or a cascading failure, whether resulting from either a sudden disturbance, including a cybersecurity incident, or an unanticipated failure of the system elements. In order to avoid these outcomes, the various elements and components of the Bulk-Power System are to be operated within equipment and electric system thermal, voltage and stability limits.[22]

25. Third, section 215 of the FPA explains that the Bulk-Power System broadly encompasses both the facilities

[16] *Mandatory Reliability Standards for the Bulk Power System,* Notice of Proposed Rulemaking, 71 FR 64,770 (Nov. 3, 2006), FERC Stats. & Regs., Vol IV, Proposed Regulations, ¶ 32,608 (2006).

[17] The modified 20 Reliability Standards are: CIP–001–1; COM–001–1; COM–002–2; EOP–002–2; EOP–003–1; EOP–004–1; EOP–006–1; INT–001–2; INT–003–2; IRO–001–1; IRO–002–1; IRO–003–2; IRO–005–2; PER–004–1; PRC–001–1; TOP–001–1; TOP–002–2; TOP–004–1; TOP–006–1; and TOP–008–1.

[18] *See* NERC comments, Attachment B.

[19] NOPR at P 14.

[20] Generally speaking, the nation's Bulk-Power System has been described as consisting of ''generating units, transmission lines and substations, and system controls.'' *Maintaining Reliability in a Competitive U.S. Electricity Industry, Final Report of the Task Force on Electric System Reliability,* Secretary of Energy Advisory Board, U.S. Department of Energy (September 1998) at 2, 6–7. The transmission component of the Bulk-Power System is understood to provide for the movement of power in bulk to points of distribution for allocation to retail electricity customers. Essentially, transmission lines and other parts of the transmission system, including control facilities, serve to transmit electricity in bulk from generation sources to concentrated areas of retail customers, while the distribution system moves the electricity to where these retail customers consume it at a home or business.

[21] 16 U.S.C. 824o(a)(3).

[22] ''The term 'reliable operation' means operating the elements of the Bulk-Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.'' 16 U.S.C. 824o(a)(4).

and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) as well as the electric energy from generation facilities needed to maintain transmission system reliability.[23] Further, section 215 explains that the interconnected transmission network within an Interconnection is a geographic area in which the operation of Bulk-Power System components is synchronized such that the failure of one such component, or more than one such component, may adversely affect the ability of the operators of other components within the system to maintain reliable operation of the facilities within their control.[24] A Cybersecurity Incident is explained to be a malicious act that disrupts or attempts to disrupt the operation of programmable electronic devices and communication networks including hardware, software or data that are essential to the reliable operation of the Bulk-Power System.[25]

26. Next, as to the reliability roles of the Commission and others, section 215 of the FPA explains that the ERO must file each of its Reliability Standards and any modification thereto with the Commission.[26] The Commission will consider a number of factors before taking any action with respect thereto. We may approve the Reliability Standard or its modification only if we determine that it is just, reasonable, and not unduly discriminatory or preferential and in the public interest to do so. Also, in doing so, we are instructed to give due weight to the technical expertise of the ERO concerning the content of a proposed standard or a modification thereto. We must also give due weight to an Interconnection-wide Regional Entity with respect to a proposed Reliability Standard to be applicable within that Interconnection, except for matters concerning the effect on competition.[27]

27. Similarly, in considering whether to forward a proposed Reliability Standard to the Commission for approval, the ERO must rebuttably presume that a proposal from a Regional Entity organized on an Interconnection-wide basis for a Reliability Standard or modification to a Reliability Standard to be applicable on an Interconnection-wide basis is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.[28] The Commission may also give deference to the advice of a Regional Advisory Body organized on an Interconnection-wide basis in regard to whether a proposed Reliability Standard is just, reasonable and not unduly discriminatory or preferential and in the public interest, as it may apply within the region.[29]

28. Finally, the Commission is further instructed to remand to the ERO for further consideration any standard or modification that it does not approve in whole or part.[30] We may also direct the ERO to submit a proposed Reliability Standard or modification that addresses a specific problem if we consider this course of action to be appropriate.[31] Further, if we find that a conflict exists between a Reliability Standard and any function, rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by the Commission applicable to a transmission organization,[32] and if we determine that the Reliability Standard needs to be changed as a result of such a conflict, we must order the ERO to develop and file with the Commission a modified Reliability Standard for this purpose.[33]

3. Balancing the Need for Practicality With the Mandates of Section 215 and Order No. 672

29. In enacting section 215, Congress chose to expand the Commission's jurisdiction beyond our historical role as primarily an economic regulator of the public utility industry under Part II of the FPA. Many entities not previously touched by our economic regulatory oversight are within our reliability purview and these entities will have to familiarize themselves not only with the new reliability obligations under section 215 of the FPA and the Reliability Standards that we are approving in this Final Rule, but also any proposed Reliability Standards or improvements that may implicate them that are under development by the ERO and the Regional Entities.[34] We have taken these and other considerations into account and have tried to reach an appropriate balance among them.

30. First, we have decided, as proposed in our NOPR, to approve most of the Reliability Standards that the ERO submitted in this proceeding, even though concerns with respect to many of the Reliability Standards have been voiced. As most of these Reliability Standards are already being adhered to on a voluntary basis, we are concerned that to remand them and leave no standard in place in the interim would not help to ensure reliability when such standards could be improved over time. In these cases, however, the concerns highlighted below merit the serious attention of the ERO and we are directing the ERO to consider what needs to be done and how to do so, often by way of descriptive directives.[35]

31. We emphasize that we are not, at this time, mandating a particular

[23] 16 U.S.C. 824o(a)(1).

[24] 16 U.S.C. 824o(a)(5).

[25] 16 U.S.C. 824o(a)(8).

[26] ''The Electric Reliability Organization shall file each Reliability Standard or modification to a Reliability Standard that it proposes to be made effective under this section with the Commission.'' 16 U.S.C. 824o(d)(1).

[27] ''The Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission shall give due weight to the technical expertise of the Electric Reliability Organization with respect to the content of a proposed standard or modification to a Reliability Standard and to the technical expertise of a regional entity organized on an Interconnection-wide basis with respect to a Reliability Standard to be applicable within that Interconnection, but shall not defer with respect to the effect of a standard on competition. A proposed standard or modification shall take effect upon approval by the Commission.'' 16 U.S.C. 824o(d)(2).

[28] 16 U.S.C. 824o(d)(3).

[29] 16 U.S.C. 824o(j).

[30] 16 U.S.C. 824o(d)(4).

[31] 16 U.S.C. 824o(d)(5).

[32] Under section 215, a transmission organization is a RTO, ISO, independent transmission provider or other Transmission Organization finally approved by the Commission for the operation of transmission facilities. 16 U.S.C. 824o(a)(6).

[33] 16 U.S.C. 824o(d)(6).

[34] Section 215(b) of the FPA provides that, for purposes of approving Reliability Standards and enforcing compliance with such standards, the Commission shall have jurisdiction over those entities that had previously been excluded under section 201(f) of the FPA. Section 201(f) excludes the United States, a state or any political subdivision of a state, an electric cooperative that receives financing under the Rural Electrification Act of 1936, 7 U.S.C. 901 *et seq.*, or that sells less than 4,000,000 megawatt hours of electricity per year, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto. 16 U.S.C. 824(f).

[35] In Order No. 672, we decided, in response to some commenters' suggestions that a Reliability Standard should address the ''what'' and not the ''how'' of reliability and that the actual implementation should be left to entities such as control area operators and system planners, that in some limited situations, there may be good reason to do so but, for the most part, in other situations the ''how'' may be inextricably linked to the Reliability Standard and may need to be specified by the ERO to ensure the enforcement of the standard. Since leaving out implementation features could sacrifice necessary uniformity, create uncertainty for the entity that has to follow the standard, make enforcement difficult, or increase the complexity of the Commission's oversight and review process, we left it to the ERO to reach the appropriate balance between reliability principles and implementation features. Order No. 672 at P 260. We also decided that the Commission's authority to order the ERO to address a particular reliability topic is not in conflict with other provisions of Order No. 672 that assigned the responsibility for developing a proposed Reliability Standard to the ERO. Order No. 672 at P 416.

outcome by way of these directives, but we do expect the ERO to respond with an equivalent alternative and adequate support that fully explains how the alternative produces a result that is as effective as or more effective that the Commission's example or directive.

32. We have sought to provide enough specificity to focus the efforts of the ERO and others adequately. We are also sensitive to the concern of the Canadian Federal Provincial Territorial Working Group (FPT) about the status of an existing standard that is already being followed on a voluntary basis. The FPT suggests, for example, that instead of remanding an existing Reliability Standard, the Commission should conditionally approve the standard pending its modification.[36] We believe the action we take today is similar in many respects to this approach.

33. We have also adopted a number of other measures to mitigate many of the difficulties associated with the electric utility industry's preparation for and transition to mandatory Reliability Standards. For instance, we are directing the ERO and Regional Entities to focus their enforcement resources during an initial period on the most serious Reliability Standard violations. Moreover, because commenters have raised valid concerns as discussed below, our Final Rule relies on the existing NERC definition of bulk electric system and its compliance registration process to provide as much certainty as possible regarding the applicability and responsibility of specific entities under the approved standards. This approach should also assuage the concerns of many smaller entities.

B. Discussion of the Commission's New Regulations

1. Applicability

34. In the NOPR, the Commission proposed to add § 40.1(a) to the regulations. The Commission proposed that § 40.1(a) would provide that this Part applies to all users, owners and operators of the Bulk-Power System within the United States (other than Alaska and Hawaii) including, but not limited to, the entities described in section 201(f) of the FPA. This statement is consistent with section 215(b) of the FPA and § 39.2 of the Commission's regulations.

35. The Commission further proposed to add § 40.1(b), which would require each Reliability Standard made effective under this Part to identify the subset of users, owners and operators to whom that particular Reliability Standard applies.

a. Comments

36. NERC agrees with the Commission's proposal to add the text of § 40.1(b) to its regulations to require that each Reliability Standard identify the subset of users, owners and operators to which that particular Reliability Standard applies and believes this requirement is currently established in NERC's Rules of Procedure.

37. TANC supports proposed § 40.1. It states that requiring each Reliability Standard to identify the subset of users, owners and operators to whom it applies, thereby limiting the scope of the broad phrase ''users, owners and operators,'' is a critical step to removing ambiguities from the Reliability Standards. According to TANC, the proposed text of § 40.1 would eliminate ambiguities with regard to the entity responsible for complying with each Reliability Standard. In this way, Regional Entities and other interested parties will be allowed to weigh in during the Reliability Standards development process on the breadth of each standard and may urge NERC to accept any necessary regional variations that are necessary to maintain adequate reliability within the region.

38. APPA believes that the Commission's proposal to add § 40.1 and 40.2 to its regulations is generally appropriate and acceptable, but the regulatory language should be amended to make clear the exact universe of users, owners and operators of the Bulk-Power System to which the mandatory Reliability Standards apply. It recommends that the regulations provide that determinations as to applicability of standards to particular entities shall be resolved by reference to the NERC compliance registry.

b. Commission Determination

39. The Commission adopts the NOPR's proposal to add § 40.1 to the Commission's regulations. The Commission disagrees with APPA's suggestion to define here the exact universe of users, owners and operators of the Bulk-Power System to which the mandatory Reliability Standards apply. Rather, consistent with NERC's existing approach, we believe that it is appropriate that each Reliability Standard clearly identify the subset of users, owners and operators to which it applies and the Commission determines applicability on that basis. As we discuss later, we approve NERC's current compliance registry to provide certainty and stability in identifying which entities must comply with particular Reliability Standards.

2. Mandatory Reliability Standards

40. The Commission proposed to add § 40.2(a) to the Commission's regulations. The proposed regulation text would require that each applicable user, owner and operator of the Bulk-Power System comply with Commission-approved Reliability Standards developed by the ERO, and would provide that the Commission-approved Reliability Standards can be obtained from the Commission's Public Reference Room at 888 First Street, NE., Room 2A, Washington, DC 20426.

41. The Commission further proposed to add § 40.2(b) to its regulations, providing that a modification to a Reliability Standard proposed to become effective pursuant to § 39.5 shall not be effective until approved by the Commission.

a. Comments

42. NERC concurs with the Commission's proposal to require NERC to provide to the Commission a copy of all approved Reliability Standards for posting in its Public Reference Room. NERC agrees with the Commission that neither the text nor the title of an approved Reliability Standard should be codified in the Commission's regulations.

b. Commission Determination

43. For the reasons discussed in the NOPR, the Commission generally adopts the NOPR's proposal to add § 40.2 to the Commission's regulations.[37] However, after consideration, the Commission has determined that it is not necessary to have the approved Reliability Standards on file in the Commission's public reference room and on the NERC Web site. Therefore, we will require that all Commission-approved Reliability Standards be available on the ERO's Web site, with an effective date, and revise § 40.2(b) to remove the following language: ''Which can be obtained from the Commission's Public Reference Room at 888 First Street, NE., Room 2A, Washington, DC, 20426.'' Further, to be consistent with Part 39 of our regulations, we remove the reference to NERC and replace it with ''Electric Reliability Organization.''

3. Availability of Reliability Standards

44. The Commission proposed to add § 40.3 to the regulation text, which requires that the ERO maintain in electronic format that is accessible from the Internet the complete set of effective

[36] FPT letter to Chairman Kelliher (submitted on July 10, 2006) (placed in the record of this proceeding).

[37] NOPR at P 37.

Reliability Standards that have been developed by the ERO and approved by the Commission. The Commission stated that it believes that ready access to an electronic version of the effective Reliability Standards will enhance transparency and help avoid confusion as to which Reliability Standards are mandatory and enforceable. We noted that NERC currently maintains the existing, voluntary Reliability Standards on the NERC Web site.

45. While the NOPR discusses each Reliability Standard and identifies the Commission's proposed disposition for each Reliability Standard, we did not propose to codify either the text or the title of an approved Reliability Standard in the Commission's regulations. Rather, we proposed that each user, owner or operator of the Bulk-Power System must comply with applicable Commission-approved Reliability Standards that are available in the Commission's Public Reference Room and on the Internet at the ERO's Web site. We stated that this approach is consistent with the statutory options of approving a proposed Reliability Standard or modification to a Reliability Standard ''by rule or order.'' [38]

a. Comments

46. NERC states that it can successfully implement the Commission's proposal to require NERC to maintain in electronic format that is accessible from the Internet the complete set of Reliability Standards that have been developed by the ERO and approved by the Commission. NERC currently maintains a public Web site displaying the existing, voluntary Reliability Standards for access by users, owners and operators of the Bulk-Power System. Once the proposed Reliability Standards are approved by the Commission, NERC will modify its Web site to distinguish which Reliability Standards have been approved by the Commission for enforcement in the United States.

47. EEI states that the approval of Reliability Standards should be through a rulemaking rather than an order, except in very rare circumstances, because of the open nature of the rulemaking process. Where the Commission decides to proceed by order, EEI states that the Commission should give notice and an opportunity to comment on any proposed Reliability Standards.

b. Commission Determination

48. For the reasons discussed in the NOPR, the Commission adopts the NOPR's proposal to add § 40.3 to the Commission's regulations; however the Commission has further clarified the proposed regulatory text.[39] We clarify that the ERO must post on its Web site the currently effective Reliability Standards as approved and enforceable by the Commission. Further, we require the effective date of the Reliability Standards must be included in the posting.

49. In response to EEI, the Commission anticipates that it will address most, if not all, new Reliability Standards proposed by NERC through a rulemaking process. However, we retain the flexibility to address matters by order where appropriate, consistent with the statute and our regulations.[40] In Order No. 672, the Commission stated that it would provide notice and opportunity for public comment except in extraordinary circumstances and, on rehearing, clarified that any decision by the Commission not to provide notice and comment when reviewing a proposed Reliability Standard will be made in accordance with the criteria established in section 553 of the Administrative Procedure Act.[41]

C. Applicability Issues

1. Bulk-Power System v. Bulk Electric System

50. The NOPR observed that, for purposes of section 215, ''Bulk-Power System'' means:

> (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.

51. The NERC glossary, in contrast, states that Reliability Standards apply to the ''bulk electric system,'' which is defined by its regions in terms of a voltage threshold and configuration, as follows:

> As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.[42]

52. In the NOPR, the Commission proposed that, for the initial approval of proposed Reliability Standards, the continued use of NERC's definition of bulk electric system as set forth in the NERC glossary is appropriate.[43] However, the Commission interpreted the term ''bulk electric system'' to apply to: (1) All of the ≥ 100 kV transmission systems and any underlying transmission system (< 100 kV) that could limit or supplement the operation of the higher voltage transmission systems and (2) transmission to all significant local distribution systems (but not the distribution system itself), transmission to load centers and transmission connecting generation that supplies electric energy to the system. The Commission proposed that, if a question arose concerning which underlying transmission system limits or supplements the operation of the higher voltage transmission system, the ERO would determine the matter on a case-by-case basis.

53. The Commission solicited comment on its interpretation and whether the Regional Entities should, in the future, play a role in either defining the facilities that are subject to a Reliability Standard or be allowed to determine an exception on a case-by-case basis.

54. Further, the NOPR explained that continued reliance on multiple regional interpretations of the NERC definition of bulk electric system, which omits significant portions of the transmission system component of the Bulk-Power System that serve critical load centers, is not appropriate. Thus, the NOPR proposed that, in the long run, NERC revise the current definition of bulk electric system to ensure that all facilities, control systems and electric energy from generation resources that impact system reliability are included within the scope of applicability of Reliability Standards, and that NERC's revision is consistent with the statutory term Bulk-Power System.

a. Comments

55. Most commenters, including NERC, NARUC, APPA, National Grid, EEI and Ontario IESO, believe that the Commission should only impose Reliability Standards on those entities that fall under NERC's definition of bulk electric system as it existed under the voluntary regime. They state that, by extending the definition of bulk electric system, the Commission goes beyond

[38] *See* 16 U.S.C. 824o(d)(2).

[39] NOPR at P 39–41.

[40] *See* 16 U.S.C. 824o(d)(2) (''the Commission may approve, by rule or order, a proposed Reliability Standard or modification * * *''); 18 CFR 39.5(c).

[41] *See* Order No. 672 at P 308; Order No 672–A at P 26.

[42] NERC Glossary at 2. All citations to the Glossary in this Final Rule refer to the November 1, 2006 version filed on November 15, 2006.

[43] NOPR at P 66–70. The Commission explained in the NOPR that regional definitions had not been submitted and it would not determine the appropriateness of any regional definition in the current rulemaking proceeding. *Id.* at n. 56.

what is necessary to protect Bulk-Power System reliability, creates uncertainty and will divert resources from monitoring compliance of those entities that could have a material impact on Bulk-Power System reliability.

56. Entergy, however, agrees with the Commission that NERC's definition of bulk electric system is not adequate and agrees with the Commission's proposed interpretation. ISO-NE does not oppose the NOPR's approach on how to interpret the term ''Bulk-Power System,'' but it states that this broader scope justifies a delay in the date civil penalties take effect, to January 1, 2008, to provide the industry sufficient time to review the Commission's Final Rule and to adjust to the expanded reach of the Reliability Standards.

57. NERC, APPA and NRECA maintain that there was no intentional distinction made by Congress between ''Bulk-Power System'' (as defined in section 215) and the ''bulk electric system'' (as defined by the NERC glossary). NERC asserts that recent discussions with stakeholders confirm NERC's belief that there was no distinction intended. Moreover, NERC is not aware of any documentation that suggests a distinction was intended. NRECA argues that legislative intent and prior usage do not support the Commission's approach to defining the Bulk-Power System. NRECA concedes that no conference committee report accompanied EPAct 2005, but it notes that the Congressional Research Service specifies in its manual on statutory interpretation that ''[W]here Congress borrows terms of art in which are accumulated the legal tradition and meaning of centuries of practice, it presumably knows and adopts the cluster of ideas that were attached to each borrowed word in the body of learning from which it was taken.'' [44]

58. TAPS states that the Commission cannot lawfully ''interpret'' the bulk electric system definition contrary to its terms. According to TAPS, the Commission cannot include facilities below 100 kV ''that could limit or supplement the operation of the higher voltage transmission systems,'' in the bulk electric system, even if they are ''necessary for operating'' the bulk system, because these facilities are not included in NERC's definition of bulk electric system.

59. NERC states that the Commission's proposal that NERC's ''bulk electric system'' should apply to all of the equal to or greater than 100 kV transmission systems and any underlying transmission system (less than 100 kV) that could limit or supplement the operation of the higher voltage transmission systems is a significant expansion over what the industry has historically regarded as the bulk electric system, both in terms of the facilities covered and the entities involved. While NERC agrees with the Commission that Congress intended to give the Commission broad jurisdiction over the reliability of the Bulk-Power System, it does not believe this is the right time for the Commission to define the full extent of its jurisdiction or that the approach proposed in the NOPR is the right way to do so. In addition, NERC does not believe it is legally necessary for the Commission to extend its jurisdiction to the limits in a single step.

60. NERC states that the Commission should make clear in this Final Rule that its jurisdiction is at least as broad as the historic NERC definition of ''bulk electric system'' and that the Commission will use that definition for the near term. NERC asserts that the Commission should also make clear that it is not deciding in this docket the full scope of its jurisdiction and is reserving its right to consider a broader definition. Instead, NERC states that the Commission should focus on approving an initial set of Reliability Standards for the core set of users, owners and operators that have the most significant impact on the reliability of the Bulk-Power System. NERC maintains that this core set has been defined through its use of the terms ''bulk electric system'' and ''responsible entities'' provided in the NERC Glossary, the ''Applicability'' section of each Reliability Standard and substantive requirements of the standards themselves, and NERC's registration of specific entities that are responsible for compliance with the Reliability Standards.

61. NRECA argues that the definition of ''Bulk-Power System'' contained in section 215(a)(1) reflects Congressional intent to codify the established materiality component because Congress limited the definition of Bulk-Power System to facilities and control systems necessary for operating an interconnected electric energy transmission network and electric energy from generation facilities needed to maintain transmission system reliability. NRECA argues that these limiting terms mean that not all transmission facilities are included. In NRECA's view, the definition of the Bulk-Power System within the meaning of section 215 cannot extend to radial facilities to ''significant local distribution systems,'' ''load centers,'' or local transmission facilities unless otherwise ''necessary for'' (*i.e.*, material to) the reliable operation of the interconnected grid. Further, NRECA states that the definition of ''Reliable Operation'' in section 215(a) focuses on the reliable operation of the Bulk-Power System and not the protection of local load per se.

62. Certain commenters assert that expanding the scope of the Commission's jurisdiction and the scope of the Reliability Standards in this proceeding would be an unanticipated expansion of the reach of the existing Reliability Standards implemented with insufficient due process and may cause jurisdictional concerns.[45] They state that the Reliability Standards under consideration were developed and approved through NERC's Reliability Standards development process with the intention that they would apply based on the industry's historical conception of the bulk electric system and that the outcome might have been different using the Commission's proposed definition. NERC therefore argues that it would be inappropriate to assume that the requirements of the existing Reliability Standards would be relevant to an expanded set of entities or an expanded scope of facilities under a broader definition of the Bulk-Power System. NERC also asserts that there is no reasonable justification for subjecting ''thousands of small entities'' to the costs of compliance with the Reliability Standards when there is no reasonable justification to do so in terms of incremental benefit to the reliability of the Bulk-Power System.

63. NRECA, APPA and others argue that the Commission's interpretation would undermine, rather than promote, reliability. According to these commenters, the Commission's interpretation would require new definitions, such as one for ''load center,'' and otherwise creates confusion. For example, Small Entities Forum states that it is concerned with the inclusion of ''transmission connecting generation that supplies electric energy to the system'' because that could include any transmission connected to any generation of any size.

64. APPA objects to the Commission's statement that ''[t]he transmission system component of the Bulk-Power System is understood to provide for the movement of power in bulk to points of distribution for allocation to retail electricity customers.'' APPA states that it does not believe there is an industry ''understanding'' that the bulk electric system or the Bulk-Power System

[44] NRECA, citing *Morissette* v. *United States,* 342 U.S. 246, 263 (1952).

[45] *See, e.g.*, NERC, TAPS and NRECA.

necessarily encompass all transmission facilities that connect major generation stations to distribution systems or that there is a bright line between transmission and distribution facilities. APPA interprets these terms as describing the backbone facilities that integrate regional transmission networks.

65. NERC's approach to moving forward with the enforcement of mandatory Reliability Standards is to register the specific entities that NERC will hold accountable for compliance with the Reliability Standards. The registration will identify all entities that are material to the reliability of the Bulk-Power System. NERC maintains its most important role is to mitigate noncompliant behavior regardless of an entity's registration. Further, NERC asserts that all that it and the Commission give up by using the registration approach is, at most, ''one penalty, one time'' for an entity. That is, if there is an entity that is not registered and NERC later discovers that the entity can have a material impact on the reliability of the Bulk-Power System, NERC has the ability to add the entity, and possibly other entities of a similar class, to the registration list and to direct corrective action by that entity on a going forward basis.[46] Thereafter, of course, the entity would be subject to sanctions. APPA, TANC, AMP-Ohio and NPCC support this approach. While SoCal Edison believes that there can be no single definition of Bulk-Power System, it states that NERC's registry is a good starting point to developing general criteria for what facilities should be subject to the Reliability Standards.

66. AMP-Ohio supports NERC's proposal to include any additional entities or facilities that it believes could have a detrimental effect on the reliability of the bulk electric system on a case-by-case basis over time. Further, Ontario IESO suggests that if the Commission believes that NERC's definition of bulk electric system excludes facilities that should be subject to Reliability Standards for reasons other than preventing cascading outages, the Commission could submit a detailed request through the ERO Reliability Standards development process.

67. NERC and EEI believe that, in the long run, NERC should be directed to develop, through its Reliability Standards development process, a single process to identify the specific elements of the Bulk-Power System that must comply with Reliability Standards under section 215. According to NERC, the Commission, the states, and all other stakeholders would benefit tremendously from a deliberate dialogue on these matters. NERC asks that the Commission not directly define the outer limits of its jurisdiction under section 215, but requests that the Commission direct NERC to undertake certain activities to reconcile the definitions of bulk electric system and Bulk-Power System and report the results back to the Commission.

68. Similarly, TAPS, APPA, Duke and MidAmerican state that, if there is a problem with NERC's current definition of the bulk electric system, the Commission should require NERC to revisit it using the ANSI process to give ''due weight'' to NERC's technical expertise. AMP-Ohio, TANC, Georgia Operators and Entergy state that Regional Entities should play a primary role in defining the facilities that are subject to a Reliability Standard because the Regional Entities will have more detailed system knowledge in their regions than NERC or the Commission.

69. The Connecticut Attorney General, the Connecticut DPUC and the New England Conference of Public Utilities Commissioners maintain that NERC's definition of the ''bulk electric system'' exceeds the Commission's jurisdiction by including generation that is not needed to maintain transmission system reliability and therefore intrudes into state jurisdiction over generation resource adequacy matters and is unlawful. According to Connecticut DPUC, section 215(a)(1) of the FPA excludes from federal regulation (1) facilities that are used in local distribution, (2) facilities and control systems that are not necessary for operating an interconnected electric energy transmission network or part of a network and (3) electric energy from generating facilities not needed to maintain transmission system reliability. Connecticut DPUC maintains that, in contrast, NERC's definition replaces the FPA definition with criteria based on voltage thresholds for transmission facilities and electric energy from generating facilities. According to Connecticut DPUC, NERC's definition does not comply with section 215(a)(1) because it includes facilities and equipment that are neither ''necessary'' for operation of the transmission network nor ''needed'' to maintain transmission system reliability. The Connecticut Attorney General and Connecticut DPUC, therefore, urge the Commission to reject this definition.

70. Further, in Connecticut DPUC's view, because the Commission cannot adopt NERC's definition of bulk electric system, it cannot expand the boundaries of its jurisdiction farther than the bulk electric system. It maintains that Congress did not give the Commission jurisdiction to mandate and enforce all Reliability Standards, especially those related to the long-term adequacy of generation resources; therefore, the Commission may not delegate to an ERO authority that it does not have. APPA also states that the Commission expanded the definition of the bulk electric system so that it may affect facilities subject to state reliability jurisdiction, such as low-voltage transmission systems that affect only the local areas served by those facilities, which do not cause cascading outages, without explaining why it is necessary to federalize reliability responsibility for outages on these facilities.

71. NARUC and New York Commission maintain that the Commission's proposed interpretation of what facilities constitute the Bulk-Power System is inconsistent with section 215 of the FPA. They state that the ability of a facility to ''limit or supplement'' the transmission system does not automatically mean that a facility is necessary for operating an interconnected transmission system, as required by the FPA, or for maintaining system reliability. According to NARUC, Congress only authorized the Commission to approve Reliability Standards necessary for operating an interconnected electric energy transmission network. Although the NOPR interpretation includes these underlying facilities, it also covers others that are not required to operate an interconnected transmission network.

72. Moreover, NARUC and New York Commission state that the NOPR proposal to define Bulk-Power System as all facilities operating at or above 100 kV exceeds the Commission's jurisdiction. According to NARUC and New York Commission, there is generally a layer of ''area'' transmission facilities below the ''Bulk-Power System'' and above distribution facilities that move energy within a service territory and toward load centers. However, NARUC and New York Commission claim that only a small subset of these underlying facilities assists in maintaining the reliability of the Bulk-Power System.

73. Several commenters, including New York Commission, NYSRC, Massachusetts DTE, NPCC, TANC and Ontario IESO, support a functional, impact-based approach to applying Reliability Standards. According to NPCC, neither NERC nor section 215 of the FPA provide a rigorous approach to

[46] *See* Rules of Procedure, § 500.

determining which elements play a role in maintaining reliability of the bulk electric system. These commenters generally state that an impact-based approach would define those elements necessary for Reliable Operation and ensure that compliance and enforcement efforts concentrate on those facilities that materially affect the Reliable Operation of the interconnected Bulk-Power System, while at the same time balancing the costs imposed by mandatory Reliability Standards with the reliability improvement realized on the interconnected Bulk-Power System.

74. Ontario IESO maintains that reliability impact is a process of assessing facilities to determine if, due to recognized contingencies and other test criteria, they represent a significant adverse impact beyond a local area. This assessment will be the basis of a consistent test methodology the ERO must develop to define the facilities included within the overall Bulk-Power System to which a Reliability Standard would apply. Ontario IESO states that the Commission should direct the ERO to take the lead in developing the impact assessment procedure to provide a consistent and uniform methodology that can be applied by any Regional Entity. Ontario IESO does not support the Commission's proposal to limit case-by-case determinations to underlying transmission systems operating at less than 100 kV.

b. Commission Determination

75. The Commission agrees with commenters that, at least initially, expanding the scope of facilities subject to the Reliability Standards could create uncertainty and might divert resources as the ERO and Regional Entities implement the newly created enforcement and compliance regime. Further, we agree with commenters that unilaterally modifying the definition of the term bulk electric system is not an effective means to achieve our goal. For these reasons, the Commission is not adopting the proposed interpretation contained in the NOPR. Rather, for at least an initial period, the Commission will rely on the NERC definition of bulk electric system [47] and NERC's registration process to provide as much certainty as possible regarding the applicability to and the responsibility of specific entities to comply with the Reliability Standards in the start-up phase of a mandatory Reliability Standard regime.[48]

76. However, we disagree with NERC, APPA and NRECA that there is no intentional distinction between Bulk-Power System and bulk electric system. NRECA states that ''[W]here Congress borrows terms of art in which are accumulated the legal tradition and meaning of centuries of practice, it presumably knows and adopts the cluster of ideas that were attached to each borrowed word in the body of learning from which it was taken.'' [49] In this instance, however, Congress did not borrow the term of art—bulk electric system—but instead chose to create a new term, Bulk-Power System, with a definition that is distinct from the term of art used by industry. In particular, the statutory term does not establish a voltage threshold limit of applicability or configuration as does the NERC definition of bulk electric system. Instead, section 215 of the FPA broadly defines the Bulk-Power System as ''facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) [and] electric energy from generating facilities needed to maintain transmission system reliability.'' Therefore, the Commission confirms its statements in the NOPR that the Bulk-Power System reaches farther than those facilities that are included in NERC's definition of the bulk electric system.[50]

77. Although we are accepting the NERC definition of bulk electric system and NERC's registration process for now, the Commission remains concerned about the need to address the potential for gaps in coverage of facilities. For example, some current regional definitions of bulk electric system exclude facilities below 230 kV and transmission lines that serve major load centers such as Washington, DC and New York City.[51] The Commission intends to address this matter in a future proceeding. As a first step in enabling the Commission to understand the reach of the Reliability Standards, we direct the ERO, within 90 days of this Final Rule, to provide the Commission with an informational filing that includes a complete set of regional definitions of bulk electric system and any regional documents that identify critical facilities to which the Reliability Standards apply (*i.e.*, facilities below a 100 kV threshold that have been identified by the regions as critical to system reliability).

78. The Commission believes that the above approach satisfies concerns raised by NARUC and New York Commission that the proposal to interpret Bulk-Power System exceeds the Commission's jurisdiction. When the Commission addresses this matter in a future proceeding, it will consider NARUC's and New York Commission's comments regarding the ''layer of 'area' transmission.''

79. We disagree with commenters claiming that the ERO's definition of bulk electric system is *broader* than the statutory definition of Bulk-Power System. Connecticut Attorney General, Connecticut DPUC and others argue that the ERO's definition of bulk electric system exceeds the Commission's jurisdiction by including generation that is not needed to maintain transmission system reliability and, therefore, intrudes into state jurisdiction over generation resource adequacy. First, none of the Reliability Standards submitted by the ERO set requirements for resource adequacy. Moreover, commenters have not adequately supported their claim that the ''threshold'' in the NERC definition of bulk electric system that includes facilities ''*generally* operated at 100 kV or higher'' is broader than the statutory phrase ''electric energy from generation facilities needed to maintain transmission system reliability.'' As stated explicitly in the NERC definition, this is a ''general'' threshold and allows leeway to address specific circumstances. On its face, the NERC definition is not overbroad; as applied, it must be interpreted and applied consistent with the statutory language in section 215. Finally, as stated above, we believe that the ERO definition of bulk electric system is narrower than the statutory definition of Bulk-Power System.

2. Applicability to Small Entities

80. The NOPR discussed NERC's plan to, in the future, identify in a particular Reliability Standard limitations on applicability based on electric facility characteristics.[52] The Commission agreed that it is important to examine the impact a particular entity may have on the Bulk-Power System in determining the applicability of a specific Reliability Standard. However,

[47] ''As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.''

[48] *See* Section II.C.2., Applicability to Small Entities, infra.

[49] Citing *Morissette* v. *United States,* 342 U.S. 246, 263 (1952).

[50] NOPR at P 66. For these same reasons, the Commission rejects the position of those commenters that suggest the statutory definition of Bulk-Power System is more limited than the NERC definition of bulk electric system.

[51] *See id.* at P 64–65 & n.53–54.

[52] *Id.* P 49–53.

the Commission stated that a ''blanket waiver'' approach that would exempt entities below a threshold level from compliance with all Reliability Standards would not be appropriate because there may be instances where a small entity's compliance is critical to reliability. The Commission also proposed to direct NERC to develop procedures that permit a joint action agency or similar organization to accept compliance responsibility on behalf of their members.

81. In addition, the Commission solicited comment on whether, despite the existence of a threshold in a particular standard (*e.g.*, generators with a nameplate rating of 20 MW or over), the ERO or a Regional Entity should be permitted to include an otherwise exempt facility, *e.g.*, a 15 MW generator, on a facility-by-facility basis, if it determines that the facility is needed for Bulk-Power System reliability and, if so, what, if any, process the ERO or Regional Entity should provide when making such a determination.

a. Identifying Applicable Small Entities

i. Comments

82. While certain commenters, including EEI, FirstEnergy, SERC, Xcel and Entergy, agree with the Commission that a blanket waiver to exempt small entities from compliance is not appropriate because there may be instances where a small entity's compliance is critical to reliability, APPA, ELCON, Process Electricity Committee, MEAG and South Carolina E&G advocate a blanket waiver.

83. APPA notes that none of the entities that contributed to the August 14, 2003 blackout were ''small entities'' within the meaning of the Regulatory Flexibility Act. APPA and MEAG believe that the Commission's refusal to provide for a blanket waiver to small entities is counterproductive to maintaining reliability, as it will distract compliance staff at NERC and the Regional Entities from identifying and monitoring those with a material impact on reliability, and gives insufficient deference to NERC as the ERO. APPA recommends that the methods and procedures used to identify critical facilities that impact the bulk electric system, regardless of size, should be the subject of a specific set of NERC Reliability Standards. Objective, transparent study criteria and assumptions and due process for affected entities are essential to implement such standards properly. Regional Entities should take advantage of industry expertise in developing and applying the methodology for determining critical facilities.

84. According to MEAG, because the Commission has already determined that it is not bound by the NERC compliance registry,[53] the NOPR's approach leaves small systems, which do not appear on the compliance registry, confused about whether the Reliability Standards apply to them. MEAG asks the Commission to either: (1) Grant a temporary, size-based exemption to those small entities that NERC omits from its preliminary compliance registry; or (2) direct NERC to develop and file with the Commission an appropriate size-based exemption for small entities.

85. Several commenters suggest thresholds for applying Reliability Standards. MEAG states that an appropriate threshold level for an exemption, on either an interim or more permanent basis, should at least provide that a LSE or distribution provider should generally be omitted from the compliance registry if it meets the following criteria: (1) Its peak load is less than 25 MW and it is not directly connected to the Bulk-Power System; (2) it is not designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the Bulk-Power System; or (3) it is not designated as the responsible entity for facilities that are part of a required undervoltage load shedding (UVLS) program designed, installed, and operated for the protection of the Bulk-Power System. STI Capital states that there should be a rebuttable presumption that any generation facility below 50 MW does not pose a threat to reliability. Moreover, more data intensive standards are beyond the ability of small generators.

86. SERC states that exemptions should be granted through the Reliability Standards development process. The ERO and the Regional Entities can provide guidance in that process, and stakeholders have an opportunity to comment on that guidance.

87. A number of commenters, including APPA, NRECA, TANC and TAPS, ask the Commission to adopt NERC's registry guidelines and make clear that issues of applicability will be determined with reference to the NERC compliance registry.[54] TAPS asks the Commission to either approve NERC's registry criteria, or send them back to NERC for further consideration, with mandatory application of Reliability Standards deferred until NERC submits waiver criteria the Commission finds acceptable. According to TAPS, these criteria do not constitute a blanket waiver because they allow NERC and its Regional Entities to go below the general threshold requirements where they determine it is necessary.

88. California Cogeneration states that, while focusing on entities that have a material impact on the Bulk-Power System is a possible approach to applying the Reliability Standards, the proposed rule does not define how ''material impact'' may be demonstrated. According to California Cogeneration, material impact will vary among Interconnections and it may vary among individual transmission systems. Therefore, California Cogeneration states that the task of defining ''material impact'' should be remanded by the Commission to NERC for resolution through an inclusive stakeholder process. Until that process is completed, California Cogeneration maintains that the Reliability Standards should not be finally adopted as mandatory and enforceable.

89. Various Georgia cities, which are all member systems of MEAG, state that the Commission should place reasonable limits on the applicability of the proposed Reliability Standards.[55] Each maintains that the Final Rule should include a rebuttable presumption that their distribution system facilities have no material effect on Bulk-Power System reliability unless established otherwise. They suggest that such a rebuttable presumption approach would fairly establish the ''reasonable limits on applicability'' of the Reliability Standards based on their respective sizes. Similarly, Small Entities Forum supports a rebuttable presumption that any LSE or distribution provider with less than 25 MW of load would be excluded unless a Regional Entity decides that a reason exists to include it.

90. California Cogeneration states that qualifying facilities (QFs) are exempted from section 215 of the FPA. It claims that, after passage of EPAct 2005, the Commission modified its regulations to provide that QFs are exempt from all sections of the FPA except sections 205, 206, 220, 221 and 222.[56] Further, California Cogeneration states that the

[53] *See* ERO Rehearing Order at P 108.

[54] NERC has developed a Statement of Compliance Registry Criteria that provides guidance on how NERC will identify organizations that may be candidates for registration. *See* NERC comments, Attachment B; NERC's February 6, 2007 supplemental filing.

[55] *See* NOPR at P 1175–76.

[56] 18 CFR 292.601(c).

Commission should set limits on whether a Reliability Standard applicable to a generator owner or operator also applies to operators of cogeneration facilities. According to California Cogeneration, the Commission has clearly determined that the impact by a cogenerator on the reliability of the system is limited to its net load on the system.[57] Therefore, California Cogeneration maintains that the Reliability Standards should reflect this limitation.

91. Finally, Small Entities Forum and Entergy state that, despite the existence of a threshold in a particular Reliability Standard, the ERO or a Regional Entity should be permitted to include an otherwise exempt facility, on a facility-by-facility basis, if it determines that the facility is needed for Bulk-Power System reliability. South Carolina E&G states that exceptions to an exemption threshold should sufficiently improve reliability so as to justify the administrative costs and other burdens. However, SMA and MidAmerican oppose allowing the ERO or its designee to include otherwise exempt facilities by making exceptions.

ii. Commission Determination

92. The Commission believes that, at the outset of this new program, it is important to have as much certainty and stability as possible regarding which users, owners and operators of the Bulk-Power System must comply with mandatory and enforceable Reliability Standards. NERC, as the ERO, has developed an approach to accomplish this through its compliance registry process. The Commission has previously found NERC's compliance registry process to be a reasonable means ''to ensure that the proper entities are registered and that each knows which Commission-approved Reliability Standard(s) are applicable to it.'' [58]

93. NERC has provided with its NOPR comments, and in a subsequent supplemental filing, a Statement of Compliance Registry Criteria that describes how NERC will identify organizations that may be candidates for registration and assign them to the compliance registry. For example, NERC plans to register only those distribution providers or LSEs that have a peak load of 25 MW or greater and are directly connected to the bulk electric system *or* are designated as a responsibility entity as part of a required underfrequency load shedding program or a required undervoltage load shedding program. For generators, NERC plans to register individual units of 20 MVA or greater that are directly connected to the bulk electric system, generating plants with an aggregate rating of 75 MVA or greater, any blackstart unit material to a restoration plan, or any generator ''regardless of size, that is material to the reliability of the Bulk-Power System.''

94. The compliance registry identifies specific categories of users, owners and operators that correlate to the types of entities responsible for performing specific functions described in the NERC Functional Model.[59] These same functional types are also used by the ERO to identify the entities responsible for compliance with a particular Reliability Standard in the Applicability section of a given standard. Thus, each registered entity will be registered under one or more appropriate functional categories, and that registration by function will determine with which Reliability Standards—and Requirements of those Reliability Standards—the entity must comply. In other words, a user, owner or operator of the Bulk-Power System would be required to comply with each Reliability Standard that is applicable to any one of the functional types for which it is registered.

95. We believe that NERC has set reasonable criteria for registration and, thus, we approve the ERO's compliance registry process as an appropriate approach to allow the ERO, Regional Entities and, ultimately, the entities responsible for compliance with mandatory Reliability Standards to know which entities are responsible for initial implementation of and compliance with the new Reliability Standards. Further, based on supplemental comments of APPA, TAPS and NRECA, it appears that there is support among many of the smaller entities for the NERC compliance registry process.[60] Thus, at this juncture, the Commission will rely on the NERC registration process to identify the set of entities that are responsible for compliance with particular Reliability Standards.

96. In sum, the ERO will identify those entities that must comply with Reliability Standards in three steps: (1) The ERO will identify and register those entities that fall under its definition of bulk electric system; (2) each registered entity will register in one or more appropriate functional categories and (3) each registered entity will comply with those Reliability Standards applicable to the functional categories in which it is registered.

97. In response to MEAG's concern that the Commission previously determined that it was not bound by the NERC compliance registry process and that there thus was uncertainty, the Commission is modifying the approach proposed in the NOPR and, as noted above, will use the NERC compliance registry to determine those users, owners and operators of the Bulk-Power System that must comply with the Reliability Standards. Each individual Reliability Standard will then identify the set of users, owners and operators of the Bulk-Power System that must comply with that standard. While the Commission may take prospective action against an entity that was not previously identified as a user, owner or operator through the NERC registration process once it has been added to the registry, the Commission will not assess penalties against an entity that has not previously been put on notice, through the NERC registration process, that it must comply with particular Reliability Standards. Under this process, if there is an entity that is not registered and NERC later discovers that the entity should have been subject to the Reliability Standards, NERC has the ability to add the entity, and possibly other entities of a similar class, to the registration list and to direct corrective action by that entity on a going-forward basis.[61] The Commission believes that this should prevent an entity from being subject to a penalty for violating a Reliability Standard without prior notice that it must comply with that Reliability Standard.

98. As stated in the NOPR, NERC has indicated that in the future it may add to a Reliability Standard limitations on applicability based on electric facility characteristics such as generator nameplate ratings.[62] While the NOPR explored this approach as a means of addressing concerns over applicability to smaller entities, the Commission believes that, until the ERO submits a Reliability Standard with such a

[57] California Cogenration at 6–7, citing *California Independent System Operator Corp.*, 96 FERC ¶ 63,015, at P 7, 24–25 (2001).

[58] *ERO Certification Order* at P 689.

[59] The Statement of Compliance Registry Criteria, as well as the Functional Model, identify, *inter alia*, the following functions: Balancing authority, distribution provider, generator operator, generator owner, load serving entity, planning authority, purchasing-selling entity, transmission owner, transmission operator and transmission service provider. An entity may be registered under one or more of these functions.

[60] *See* Supplemental Comments of TAPS (February 13, 2007), APPA (February 14, 2007), and NRECA (February 15, 2007).

[61] *See* NERC Rules of Procedure, § 500.

[62] NOPR at P 49.

limitation to the Commission, the NERC compliance registry process is the preferred method of determining the applicability of Reliability Standards on an entity-by-entity basis.

99. A number of municipalities and generation owners ask that the Commission review their particular circumstances and provide an individual waiver from compliance with the mandatory Reliability Standards. In light of our above discussion, the Commission declines to determine whether any individual municipality, generation owner or other entity is subject to a specific Reliability Standard. Rather, NERC and the Regional Entities should determine such applicability in the first instance through the registration process.

100. We agree with California Cogeneration that the Commission's regulations currently exempt most QFs from specific provisions of the FPA including section 215.[63] The Commission is concerned, however, whether it is appropriate to grant QFs a complete exemption from compliance with Reliability Standards that apply to other generator owners and operators. It is not clear to the Commission that for reliability purposes there is a meaningful distinction between QF and non-QF generators. While such an issue is beyond the scope of the current rulemaking, we note that, concurrent with the issuance of this Final Rule, the Commission is issuing a notice of proposed rulemaking that proposes to amend the Commission's regulation that exempts most QFs from section 215 of the FPA.

101. Finally, the Commission agrees that, despite the existence of a voltage or demand threshold for a particular Reliability Standard, the ERO or Regional Entity should be permitted to include an otherwise exempt facility on a facility-by-facility basis if it determines that the facility is needed for Bulk-Power System reliability.[64] However, we note that an entity that disagrees with NERC's determination to place it in the compliance registry may submit a challenge in writing to NERC and, if still not satisfied, may lodge an appeal with the Commission.[65] Therefore, a small entity may appeal to the Commission if it believes it should not be required to comply with the Reliability Standards.

[63] 18 CFR 292.601(c).

[64] Demand resources deemed critical by the ERO to Bulk-Power System reliability should be included in the registry.

[65] See ERO Certification Order at P679.

b. Ability To Accept Compliance on Behalf of Members

i. Comments

102. APPA, NERC, ELCON, APPA, TAPS and Small Entities Forum support the Commission's proposal to allow a joint action agency, generation and transmission (G&T) cooperative, or other entities to accept responsibility for compliance with Reliability Standards on behalf of their members and also may divide the responsibilities for compliance with its members. APPA states that this should also be extended to RTOs, vertically integrated utilities, and other wholesale power suppliers that perform substantial reliability functions on behalf of their full requirements wholesale customers, including public power distribution systems and other entities that currently fulfill reliability functions for customers. APPA, TAPS and Small Entities Forum state that the procedure should allow for this responsibility to be assigned on a standard-by-standard basis.

103. In response to the Commission's proposal to direct NERC to develop procedures that permit a joint action agency or similar organization to accept compliance responsibility on behalf of its members, NERC proposes the following procedure, and has updated its entity registration criteria to reflect these changes.[66] NERC states that each ''central'' organization should be able to register as being responsible for compliance for itself and collectively on behalf of its members. Each member within a central organization may separately register to be accountable for a particular reliability function defined by the standards. Under NERC's proposal, if the central organization and a member organization cannot agree that one organization or the other is responsible, or if the parties agree that the responsibilities for a particular reliability function should be split, then NERC would register both entities concurrently. NERC and the Regional Entities will then have the authority to find either organization or both accountable for a violation of a Reliability Standard, based on the facts of the case and circumstances surrounding the violation.

104. AMP-Ohio states that the Commission should clarify that a joint action agency should not be required to assume compliance responsibility for its members for all reliability-related functions. It asks that the Commission allow flexibility in how joint action agencies and their members allocate responsibility. TAPS states that joint action agencies should be allowed to achieve compliance with a standard at the joint action agency level rather than to simply stand in the shoes of their individual members. TAPS states that this is necessary to ensure comparable treatment for small entities in relation to large utilities. Where a joint action agency accepts compliance responsibility and a standard is susceptible to joint action agency-level assessment of compliance, the Commission should ask NERC to adopt such assessment to avoid an adverse impact on competition.

105. MEAG finds the Commission's proposal with regard to joint action agencies problematic. MEAG asserts that the proxy approach is not a universal approach to small municipal systems. For example, this option would be fundamentally inconsistent with MEAG's role as a G&T cooperative serving its member systems because MEAG has no authority to plan, physically operate, modify, maintain or test the local distribution system facilities of the member systems. Second, MEAG states that if it were to assume the role of the proxy compliance agent for the member systems and incur a fine for the failure of a few to comply with the requirements of the Reliability Standards, then the imposition of fines would lead to a rate increase to all systems, an improper and unjustifiable cost shifts among the member systems. Third, if MEAG were to err in its role as a proxy compliance agent for the member systems, MEAG could be sued and there is nothing that presently limits its liability or provides indemnification to MEAG in that circumstance. Moreover, MEAG states that the compliance-by-proxy option will not mitigate the economic impact on many small distribution-only entities because many are not members of joint action agencies.

106. Several commenters, including EEI, PJM and FirstEnergy do not oppose the Commission's proposal to allow organizations to accept compliance responsibility on behalf of members so long as compliance responsibility is clear and responsible entities are held accountable. FirstEnergy and PJM state that some Reliability Standards appear to have duplicate accountability in different organizational entities, which could create confusion and complicate operational authority and thus undermine the transmission operator chain of command required to respond quickly and decisively to system operational events. Further, FirstEnergy

[66] *See* NERC comments at 53–55; NERC supplemental filing, Statement of Compliance Registry Criteria (Revision 3) at 9.

states that some Reliability Standards obligate an entity to perform reliability functions when that entity may not be able to perform its reliability function due to other legal constraints. FirstEnergy states that one effective approach to resolving this problem would be to establish a ''priority'' of control between entities. FirstEnergy adds that entities that are subject to legal control by ISOs and RTOs should be afforded a ''safe harbor'' under the Reliability Standards if, during an emergency, they perform as directed by the ISO or RTO, whether under the ISO/RTO's OATT or under the ISO/RTO's authority as reliability coordinator.

ii. Commission Determination

107. The Commission directs the ERO to file procedures which permit (but do not require) an organization, such as a joint action agency, G&T cooperative or similar organization to accept compliance responsibility on behalf of its members. The Commission believes that NERC's proposed procedures described above are reasonable, and directs the ERO to submit a filing within 60 days.[67] In allowing a joint action agency, G&T cooperative or similar organization to accept compliance responsibility on behalf of its members, our intent is not to change existing contracts, agreements or other understandings as to who is responsible for a particular function under a Reliability Standard. Further, we clarify that there should not be overlaps in responsibility nor should there be any gaps.

108. In response to concerns raised by AMP-Ohio and MEAG, the Commission clarifies that an organization is not required to assume compliance responsibility for its members for any reliability-related functions and all Reliability Standards. Moreover, under NERC's proposal, a member within a central organization may separately register to be accountable for a particular reliability function so the responsibility for reliability functions can be split. The Commission believes that this will provide flexibility and will not require an entity to assume responsibility where it is not possible to do so. We also believe that NERC's proposal adequately addresses TAPS' concern that a joint action agency should be allowed to achieve compliance at the joint action agency level. Specifically, the Statement of Compliance Registry Criteria provides that a central organization can register for all functions that it performs itself and, in addition, may register on behalf of one or more of its members for functions for which the member would otherwise be required to register.[68]

109. NERC, in developing its procedures relating to joint action agencies and similar organizations, should consider the concerns of EEI, PJM and FirstEnergy regarding the need for ensuring clear lines of responsibility. While we agree with FirstEnergy in the abstract that an entity implementing the legal directives of an ISO or RTO should not be penalized for following an ISO or RTO directive during an emergency, we will not mandate a safe harbor provision for such circumstances. Rather, these and other matters should be considered by the ERO or a Regional Entity when deciding the appropriate enforcement action in response to an event where a violation of a Reliability Standard may have occurred.

3. Definition of User of the Bulk-Power System

110. In the NOPR, the Commission did not propose a generic definition of the term ''User of the Bulk-Power System.'' Rather, the Commission stated that it would determine applicability on a standard-by-standard basis.[69] The NOPR explained that § 40.1(b) of the proposed regulations would require the ERO to identify in each proposed Reliability Standard the specific subset of users, owners and operators of the Bulk-Power System to which the proposed Reliability Standard would apply, which is NERC's current practice. The NOPR also stated that entities concerned that a particular proposed Reliability Standard would apply more broadly than the statute allows may raise their concerns in the context of the specific Reliability Standard.

a. Comments

111. APPA disagrees with a standard-by-standard approach to defining the term ''user of the Bulk-Power System'' because it would go beyond those facilities that are required to maintain the reliability of the high-voltage, bulk transmission system and intrude into state and local matters and trespass on state jurisdiction. According to APPA, the Reliability Standards themselves state their applicability in terms of the Functional Model, which does not include size limitations in the various functional categories included in it. Without some type of outer limit on the ''user of the Bulk-Power System'' definition, all such entities regardless of size or their impact on the Bulk-Power System, must review every proposed Reliability Standard and protest every time they have a ''concern in the context of the specific Reliability Standard.'' They must also retain permanent staff or consultants to evaluate new or revised standards. Rather, APPA, as does TANC, urges the Commission to support NERC's registry criteria to make the definition of ''users of the Bulk-Power System'' co-extensive with the users on NERC's compliance registry.

112. SMA is concerned that not specifically defining who is a ''user of the Bulk-Power System'' will not provide timely notice to entities that are not the parties historically responsible for implementing NERC's prior reliability standards. SMA states that NERC must identify the subset of users that must comply with any given Reliability Standard at a sufficiently early stage for all such affected parties to have an opportunity to raise objections to the sweep or content of the Reliability Standard while approval of that Reliability Standard is under consideration. SMA also argues that NERC's Rules of Procedure must require actual notice to an entity before it is placed on the compliance registry.

113. Southwest TDUs urges the Commission to clarify that ''users'' are entities that have more involvement with it than merely receiving power from it. Since these Reliability Standards will become mandatory and violation of any of them can be accompanied by economically significant penalties, Southwest TDUs urges the Commission to make every effort to be specific about what constitutes a ''user.''

114. California Cogeneration states that the Commission has not provided any detail as to how a ''user'' will be identified. The NOPR and the NERC Reliability Standards it proposes to adopt rely on the broad entities identified in the NERC Functional Model. According to California Cogeneration, using only the NERC Functional Model provides no detail and no differentiation in the applicability of each Reliability Standard. While a single definition of ''user'' may not be appropriate, California Cogeneration maintains that using only the fixed designations within the NERC Functional Model does not provide sufficient specificity. The terms ''Generator Owner'' and ''Generation Operator'' also must be qualified so that they only apply to generation operations that utilize the grid and exclude

[67] Section 39.10(b) of the Commission's regulations, 18 CFR 39.10(b), provides that the Commission, upon its own motion or upon complaint, may propose a change to an ERO or Regional Entity Rule.

[68] *See* NERC Supplemental Filing, Statement of Compliance Registry Criteria (Revision 3), at 8–9.

[69] NOPR at P 43.

generation output dedicated to on-site consumption.

b. Commission Determination

115. The Commission's determination above to rely on the ERO's compliance registry process to identify users, owners and operators of the Bulk-Power System that must comply with new mandatory and enforceable Reliability Standards should resolve the concerns expressed by APPA, SMA and others regarding the need to identify and provide timely notice to those users of the Bulk-Power System that are expected to comply with specific Reliability Standards.

116. While we recognize the desire of some commenters for a concise, generic definition of ''user of the Bulk-Power System,'' we are concerned that any attempt to define the term at this time will either be overly broad so as not to provide any helpful guidance or overly narrow so as to exclude entities that should be covered. The Commission believes that it has employed a reasonable approach by endorsing NERC's compliance registry process and requiring that each Reliability Standard identify the subset of users, owners and operators to whom that particular Reliability Standard applies.

4. Use of the NERC Functional Model

117. NERC has developed a ''Functional Model'' that defines the set of functions that must be performed to ensure the reliability of the Bulk-Power System. The Functional Model identifies 14 functions and the name of a corresponding entity responsible for fulfilling each function.

118. In the NOPR, the Commission proposed to use the NERC Functional Model to identify the applicable entities to which each Reliability Standard applies.[70] The Commission explained that focusing on the functions an entity performs to identify what entities are users, owners and operators of the Bulk-Power System, and thus what entities are subject to the Reliability Standards, provides a useful level of detail and appears to be more practical than simply identifying an applicable entity as a user, owner or operator. In addition, the NOPR recognized concerns that the Functional Model may contain ambiguities and proposed to require NERC to specifically address these concerns.

119. The Commission proposed that, because the Functional Model is linked to applicability of the Reliability Standards, the ERO should submit for Commission approval any future modifications to the Functional Model that may affect the applicability of the Reliability Standards.

a. Filing the Functional Model With the Commission

i. Comments

120. NERC states that, while it believes that the Functional Model should be filed for informational purposes only, it will submit any changes to the Functional Model to the Commission for approval as requested. While NERC states that the Functional Model will not function as a legally binding document like a Reliability Standard, the Commission's approval of this reference document and of any changes to the Functional Model will support the development of high quality, enforceable and technically sufficient standards.

121. Several commenters, including NERC, EEI, APPA, MidAmerican, National Grid and MRO state that the Functional Model is not part of the Reliability Standards and should be filed with the Commission for informational purposes only. They generally state that the Functional Model is not a definitive guide to the ''users, owners and operators'' of the Bulk-Power System and should not be used to establish obligations under section 215, which should be established within each individual Commission-approved Reliability Standard.

122. Northeast Utilities is concerned with the Commission's proposal to use the NERC Functional Model to identify applicable entities. It believes that the Functional Model can be useful in drafting standards, but it is not a substitute for having clear definitions of the entities responsible for compliance with the requirements for each Reliability Standard within a region. The entities responsible for meeting the standard may vary depending on how the Bulk-Power System is operated. FirstEnergy states that the Functional Model may not clearly or correctly identify the entities to which a Reliability Standard applies and maintains that the Functional Model should be applied only where all of the affected stakeholders agree on the final classifications of each Registered Entity's roles and responsibilities.

123. In contrast, TANC and ISO–NE state that the Commission should require that any future modification to the Functional Model that could affect the categories of entities that must comply with a particular Reliability Standard be approved by the Commission because the Functional Model is so closely interrelated with the applicability of each Reliability Standard.

124. APPA, TAPS and ReliabilityFirst maintain that any modification to the NERC Functional Model should be reviewed and approved through the Reliability Standards development process. According to ReliabilityFirst, any change to the Functional Model is essentially an amendment to the Reliability Standard made outside the ERO process. TANC asserts that a Reliability Standard will only be complete if the definitions of the Functional Model are developed through the Reliability Standards development process just like any Reliability Standard. APPA would allow NERC to issue interpretations of the Functional Model, but these interpretations should then be confirmed through NERC procedures.

125. TAPS cautions that, because the Functional Model includes no express size limitations, NERC and the Commission can rely on the Functional Model to define applicability of standards only if such limits are imposed by NERC's compliance registry criteria and its bulk electric system definition. The Small Entities Forum is concerned because smaller entities have historically performed only a subset of functions. For example, it states that some joint action agencies invest in transmission facilities that are operated by others, but that these joint action agencies, under the Functional Model, would have to verify that these facilities, operated by others, are being operated and maintained according to applicable Reliability Standards.

126. Several commenters argue that the Functional Model contains a number of ambiguities. MISO argues that the definition of the term planning coordinator is circular and may lead to one subset of the transmission system having multiple Planning Coordinators. MISO recommends that the Commission direct NERC to survey the industry to identify the planning roles that actually exist in the industry and clarify the role of the wide-area Planning Coordinator. MISO and Wisconsin Electric note that the proposed Reliability Standards do not specify who fulfills the Interchange Authority or Planning Authority roles, and there is no common industry understanding of those roles. Finally, California Cogeneration states that the definition of LSE is too inclusive and should be modified to exclude entities providing service only to loads on-site or pursuant to private contract.

[70] NOPR at P 46–48.

ii. Commission Determination

127. The Commission accepts the characterization offered by numerous commenters that the Functional Model is an evolving guidance document that is not intended to convey firm rights and responsibilities. Further, we agree that the applicability section of a particular Reliability Standard should be the ultimate determinant of applicability of each Reliability Standard. In light of this, we will not require the ERO to submit revisions of the Functional Model for Commission approval. While some commenters suggest that revisions be filed for informational purposes, we see little value in mandating such a filing.[71]

128. With regard to the comments of TAPS, APPA, TANC and others on whether revisions to the Functional Model should be made through the ERO's Reliability Standards development process, we do not believe that it is necessary under the statute, since applicability will be determined at this time by the specifications of the Reliability Standards and the compliance registry process. Thus, we leave to the discretion of the ERO the appropriate means of allowing stakeholder input when revising the Functional Model. To the extent that changes in the Functional Model require revised specification in the Reliability Standards, the latter will be addressed in the Reliability Standards development process.

129. While TAPS and Small Entities Forum raise concerns regarding the absence of size limitations in the Functional Model and potential negative impacts on small entities, we believe that these concerns are addressed above in our decision regarding use of the NERC compliance registry process. MISO, Wisconsin Electric and others comment on the need to clarify certain ambiguities in the Functional Model. Given that the Functional Model is an evolving guidance document, the ERO can address such concerns as it updates and revises the Functional Model.

b. Responsibility for Functions Within the Functional Model

130. In the NOPR, the Commission explained that, in the context of an ISO or RTO or any organization that pools resources, decision-making and implementation are performed by separate groups.[72] The ISO or RTO typically makes decisions for the transmission operator and, to a lesser extent, the generation operator, while actual implementation is performed by either local transmission control centers or independent generation control centers. The NOPR proposed that ''all control centers and organizations that are necessary for the actual implementation of the decisions or are needed for operation and maintenance made by the ISO or RTO or the pooled resource organizations are part of the transmission or generation operator function in the Functional Model.'' [73]

i. Comments

131. A number of commenters raise concerns or seek clarification regarding the relationship between the Functional Model and existing agreements that set forth the responsibility of various entities, particularly in the context of ISO and RTO operations. MISO requests the Commission to clarify that nothing in the Functional Model requires one entity to be responsible for all of the tasks within a function, regardless of who actually performs the task. In those ISOs and RTOs where balancing authorities have retained and have never delegated to the RTO certain tasks that fall within the balancing authority function, NERC's Functional Model should only require one responsible entity per task rather than one responsible entity for all of the tasks within that function. MISO submits that the NERC Functional Model should not play a prescriptive role by assigning responsibility for a given task where such an assignment would be inconsistent with a Commission-approved regional transmission agreement, RTO tariff, or reliability plan filed with NERC, all of which specify the entity performing each task.

132. PJM states that, while the Commission proposed to assign responsibility for reliable operations to multiple entities within an ISO or RTO to address its concern that decision making and implementation are performed by separate organizations, it does not believe that increasing the number of organizations responsible for a given function for the same facilities within the bulk electric system has been shown to be an effective or appropriate solution to the concerns cited. PJM states that NERC employs processes that successfully manage the delegation of operational tasks while maintaining single entity accountability for the reliable performance of those operational tasks.

133. ATC states that Regional Entities should be given the flexibility to allow some ''tasks'' within a ''function'' to be performed by one entity, with the remaining tasks to be performed by another entity. According to ATC, this would provide entities—particularly smaller ones—with the flexibility to transfer their responsibility for a reliability task or function to another registered entity that can perform the work more effectively. Further, ATC maintains, Regional Entities should ensure that entities be given accountability only for systems, facilities and functions over which they actually have control.

134. NPCC states that requirements applicable to local control centers should be distinct from requirements applicable to transmission and generation operators under the NERC Functional Model. NPCC submits that there is a difference between being assigned to do a task and being responsible for the completion of that task. An organization that registers with NERC as performing a function is considered a responsible entity and must ensure that all tasks are performed. While an organization may delegate a task to another organization, it may not delegate its responsibility for ensuring that the task is accomplished.

135. According to Ontario IESO, the Commission's proposal is inconsistent with the NERC Functional Model, which envisions one responsible entity for each reliability function. In contrast, the Commission's proposal would split the same function between different organizations such as an ISO and a local control center. PJM claims that, under the Functional Model, single entity registration is a foundational cornerstone for ensuring clear responsibility and accountability for compliance with Reliability Standards.

136. Ontario IESO asserts that the Commission's proposal is also problematic because in the event of a violation it will be difficult to determine who violated the Reliability Standard—the entity making the decision or the entity implementing the decision. Ontario IESO argues that, although the NERC Functional Model is not foolproof, it avoids complications by distinguishing between responsibility and performance. The ISO is the responsible entity and it delegates some of its tasks to local control centers, but retains the overall responsibility.

137. According to Ontario IESO, NERC has recognized that, although

[71] We note that NERC has available on its Web site, *http://www/nerc.com*, the current version of the Functional Model. We expect NERC to continue to do so in the future.

[72] NOPR at P 236.

[73] *Id.* at P 237. Although discussed in the context of the communication (COM) Reliability Standards, the NOPR suggested that the proposal would apply to other Reliability Standards. Because of the nature of the comments on the issue and its relationship to the Functional Model, we discuss the matter here.

organizations such as local control centers play an important role in reliability, they are not responsible entities. Therefore, NERC has made such organizations subject to compliance audits and placed other requirements on them. In addition, NERC intends that the regional reliability plans will document the relationships between the local control centers and the entity that delegates its responsibility to such centers. The current framework has a mechanism for accommodating reliability considerations for organizations such as local control centers. In this regard, NERC's ongoing formal certification of reliability coordinator, balancing authority and transmission provider will be useful in determining any delegation of tasks to local control centers that must take place for a clear demarcation of responsibilities. Ontario IESO advises that, since NERC has not finished this task, the Commission should defer its decision in this regard.

138. ISO/RTO Council states that the Commission should not use the term ''local control center'' because it will cause confusion. The NERC Functional Model does not define the term and it means different things in different regions. For example, in MISO, which consists of 25 balancing areas, ''local control center'' is an equivalent term for balancing area although this was probably not the Commission's intent in the NOPR. Therefore, ISO/RTO Council argues that the Reliability Standards should be limited to defining the tasks in the context of users, owners and operators of the Bulk-Power System; any delegation of responsibilities to a local control center or any other organization should take place in the context of ISO/RTO governing documents, operating agreements, tariffs and other arrangements with transmission owners and related stakeholders. This approach, according to ISO/RTO Council will address the Commission's concerns with respect to local control centers without preempting possible regional solutions.

139. FirstEnergy believes that, while independent authority to operate the transmission system should be self-evident, in RTO environments with local control centers, the tasks performed by each entity do not encompass the entirety of tasks performed by the transmission operator under the Functional Model. It suggests that NERC should revise the Functional Model to create certification and registration requirements for local control authorities within RTOs that perform real-time operations of the transmission system. FirstEnergy states that a revised NERC Functional Model should recognize local control centers that take some direction from RTOs yet maintain authority to act independently to carry-out functional tasks that require real-time operation of the system. According to FirstEnergy, the required registration and certification of such entities would clearly indicate the need for operational personnel in these control rooms to be NERC-certified. It concludes that at a minimum, a NERC certification for the tasks performed by such local control center individuals would be an enhancement over the current situation.

140. ISO–NE argues that the Commission should not mandate that the tasks performed by local control centers be included in the definition of transmission operator because to do so would be to suggest that a local control center has independent autonomy in operating the Bulk Power System which would conflict with the ''one set of hands on the wheel'' philosophy. It explains that local control center personnel in New England implement tasks delegated to them by ISO–NE for operation of designated transmission facilities. Therefore, ISO–NE submits, the scope of the Reliability Standard need not be expanded.

ii. Commission Determination

141. In response to the many concerns of commenters, the Commission clarifies that it did not intend to change existing contracts, impose new organizational structures or otherwise affect existing agreements that set forth the responsibilities of various entities. Rather, its intent was to allow enough granularity in the definitions so that the appropriate user, owner or operator of the Bulk-Power System would be identified for each Reliability Standard. We agree also with MISO's statement that nothing in the Functional Model requires one entity to be responsible for all of the tasks within a function, regardless of who actually performs the task.

142. The Commission's concern is that, particularly in the ISO, RTO and pooled resource context, there should be neither unintended redundancy nor gaps for responsibilities within a function. In particular, the Commission is concerned that such ''gaps'' could occur in the context of several Reliability Standards addressing matters related to activities other than directing or implementing real-time operations.[74] For example, the involvement of a transmission operator at an ISO or RTO with respect to the requirements related to telecommunications facilities (COM–001–1) from the local control room and blackstart restoration plans (EOP–005–0) may be minimal. Because the operators at local control centers actually perform all or most of the tasks contemplated under various Reliability Standards, we are concerned that there may be unintended gaps in such responsibilities if the existing contracts between the ISO or RTO and owners of the facilities do not address such responsibilities.

143. In response to MISO, we did not intend to be prescriptive in assigning tasks to specific entities. The intent was to allow flexibility in identifying the actual user, owner or operator of the Bulk-Power System that would be responsible for complying with the Requirements in the Reliability Standards. One approach could be that the RTO, ISO or other pooled resource registers as the transmission operator pursuant to the NERC compliance registry process and, while retaining ultimate responsibility, assigns specific tasks to be performed by what are sometimes known as local control centers or other relevant organizations. Alternatively, the local control center operators could register together with the RTO, ISO or pooled resources as transmission operators clearly delineating their specific responsibilities with regard to the Requirements of particular Reliability Standards. Such joint registration must assure that there is no overlap between the decisionmaking and implementation functions, *i.e.*, that there are not two sets of hands on the wheel. Again, our intent is to ensure that there is neither redundancy nor gap in responsibility for compliance with the Requirements of a Reliability Standard, while allowing entities flexibility to determine how best to accomplish this goal.

144. Consistent with our above explanation, we agree with NPCC that there is a difference between being assigned to perform a task and being responsible for completing the task. The organization that registers with NERC to perform a function will be the

[74] *See, e.g.*, CIP–001—Sabotage Reporting; COM–001—Telecommunications; EOP–003—Load Shedding Plans; EOP–004—Disturbance Reporting; EOP–005—System Restoration Plans; EOP–008—Plans for Loss of Control Center Functionality; PRC–001—System Protection Coordination; PRC–007—Assessing Consistency with Entity Underfrequency Load Shedding Programs with Regional Reliability Organizations UFLS Program Requirements; PRC–009—Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event; PRC–010—Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program; PRC–022—UFLS Program Performance; and TOP–006—Monitoring System Conditions.

responsible entity and, while it may delegate the performance of that task to another, it may not delegate its responsibility for ensuring the task is completed.

145. Accordingly, the Commission directs that the ERO, in registering RTOs, ISOs and pooled resource organizations (or, indeed in registering any entity), assure that there is clarity in the assigning responsibility and that there are no gaps or unnecessary redundancies with regard to the entity or entities responsible for compliance with the Requirements of each relevant Reliability Standard. Accordingly, although the Commission is not requiring NERC to amend the Functional Model, we believe our concerns can be addressed by having the ERO, through its compliance registry process, ensure that each user, owner and operator of the Bulk-Power System is registered for each Requirement in the Reliability Standards that relate to transmission owners to assure there are no gaps in coverage of the type discussed here.

5. Regional Reliability Organizations

146. The NOPR stated that 28 proposed Reliability Standards would apply, in whole or in part, to a regional reliability organization.[75] Further, many of the proposed Reliability Standards that have compliance measures refer to the regional reliability organization as a compliance monitor. The Commission stated in the NOPR that it was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as proposed by NERC because it does not appear that a regional reliability organization is a user, owner or operator of the Bulk-Power System.

147. The Commission proposed to approve and direct modification of five Reliability Standards that apply partially to regional reliability organizations. For the other Reliability Standards that apply to regional reliability organizations, the Commission proposed, as an interim measure, to direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the regional reliability organizations information related to data gathering, data maintenance, reliability assessments and other process-type functions. The NOPR explained that this approach is necessary to ensure that there will be no gap during the transition from the current voluntary system to a mandatory system in which Reliability Standards are enforced by the ERO and Regional Entities. The NOPR proposed that, in the long run, Regional Entities should be made responsible, through delegation from the ERO, for the functions currently performed by the regional reliability organizations. To implement this, the Commission proposed the modification of delegation agreements to require the Regional Entities to assume responsibility for noncompliance. In addition, the Commission proposed that the Reliability Standards should be modified to apply to the users, owners and operators of the Bulk-Power System that are responsible for providing information. The Commission proposed to require that any Reliability Standard that references a regional reliability organization as a compliance monitor be modified to refer to the ERO as the compliance monitor.

148. The Commission stated that, while it is important that the existing regional reliability organizations continue to fulfill their current roles during the transition to a regime where Reliability Standards are mandatory and enforceable, the Commission does not understand why, once the transition is complete, a regional reliability organization should play a role separate from a Regional Entity whose function and responsibility is explicitly recognized by section 215 of the FPA. The Commission sought comment on whether there is any need to maintain separate roles for regional reliability organizations with regard to establishing and enforcing Reliability Standards under section 215.

a. Comments

149. NERC believes it can remove references to regional reliability organizations and Regional Entities from the Reliability Standards, with the exception of retaining the Regional Entities as the compliance enforcement authorities. However, NERC and California PUC request that the Commission reconsider its proposal to direct that the ERO be listed as the compliance monitor in each Reliability Standard. California PUC states that naming NERC as the compliance monitor deprives the Regional Entities of their enforcement role under section 215. NERC believes it will be clearer, and consistent with the delegation agreements, to designate the Regional Entity as the compliance monitor in almost all Reliability Standards. According to NERC, this would also be helpful to distinguish those few Reliability Standards that are monitored directly by NERC.

150. ReliabilityFirst, TANC and SoCal Edison agree with the Commission that regional reliability organizations and Regional Entities cannot be users, owners or operators of the Bulk-Power System and should not be subject to compliance with Reliability Standards. TANC states that Reliability Standards that reference a regional reliability organization need to be revised to reference a user, owner or operator of the Bulk-Power System in order to comply with the statute.

151. EEI agrees with the Commission's proposal to direct the ERO to require users, owners and operators to provide the information related to data gathering, data maintenance, reliability assessments and other process-type functions that previously have applied to regional reliability organizations. EEI also agrees that, in the long run, it is appropriate to make the Regional Entities responsible through delegation from the ERO for various functions now performed by regional reliability organizations. In doing so, and during the transition in particular, EEI maintains that it is important that functions now performed by the regional councils, such as planning, be continued.

152. A number of commenters discuss the possible ongoing role for a regional reliability organization. For example, Ontario IESO, NPCC and National Grid state that the Commission should recognize that the regional reliability organizations will continue to play a role in areas including developing regional reliability plans and adequacy requirements that are outside the jurisdiction of the ERO. NPCC states that enforcement of adequacy requirements should continue to reside with the regional reliability organization. National Grid states that the role of regional reliability organizations can be preserved in a variety of ways, including requiring obligations currently imposed upon regional reliability organizations to be included in the regional delegation agreements.

153. NPCC further maintains that regional reliability organizations should continue to function as regional sites for technical expertise for enhanced reliability requirements through adopting regionally-specific criteria. According to NPCC, eliminating the ability for regions to develop and propose new criteria that enhance system reliability would edge the system closer towards the lowest common denominator rather than striving towards operational excellence. Further, Ontario IESO and NPCC state that regional reliability organizations

[75] NOPR at P 54.

should be allowed to perform certain functions for their members, such as system operator workshops, forums for coordination of operations and planning and operational readiness conference calls.

154. Massachusetts DTE comments that a regional reliability organization should be allowed to propose a Reliability Standard that may exceed or enhance the proposed mandatory Reliability Standards to ensure regional reliability. It further states that any regional reliability criteria proposed by a regional reliability organization should be vetted through a regional stakeholder process and then specifically adopted by the appropriate state regulatory authorities.

155. Although MRO does not oppose regional reliability organizations, with regard to establishing and enforcing mandatory Reliability Standards, MRO, Constellation and Xcel state that there is no need to maintain a separate role for regional reliability organizations. Because Regional Entities may perform non-reliability functions, Constellation states that maintaining regional reliability organizations will result in unnecessary cost. While Constellation has no objection to the Regional Entities performing non-statutory functions, it states that the Commission should not allow Regional Entities to impose Reliability Standards developed by the regional reliability organizations as mandatory Reliability Standards.

156. MidAmerican believes that it will be important to separate the compliance functions of the Regional Entities from non-compliance functions currently assigned to the regional reliability organizations. It states that this can be done by: (1) Separating these functions internally in the Regional Entities; (2) separating these functions in different organizations; or (3) separating these functions by assigning non-compliance related functions currently assigned to the regional reliability organizations to other users, owners and operators. This will minimize conflicts between the Regional Entity core compliance function and the non-compliance regional reliability organization requirements.

b. Commission Determination

157. The Commission adopts the NOPR proposal to eliminate references to the regional reliability organization as a responsible entity in the Reliability Standards. We conclude that this approach is appropriate because, as explained in the NOPR, such entities are not users, owners or operators of the Bulk-Power System. NERC indicates that it can remove such references, except that the Regional Entity should be identified as the compliance monitor where appropriate. While the Commission originally proposed that the ERO should be designated as the compliance monitor, we agree with NERC's approach and believe that identifying the Regional Entity as the compliance monitor will provide useful specificity as to which entity will be immediately tasked with monitoring compliance with a particular Reliability Standard. However, as we stated in Order No. 672, the ERO retains responsibility to ensure that a Regional Entity implements its enforcement program in a consistent manner, and to periodically review the Regional Entity's enforcement activities.[76]

158. For those Reliability Standards that identify the regional reliability organization as the sole applicable entity, and that relate to data gathering, data maintenance, reliability assessments and other process-type functions,[77] the NOPR proposed:

> as an interim measure * * * to direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the regional reliability organizations the information related to data gathering, data maintenance, reliability assessments and other ''process''-type functions. We believe that this approach is necessary to ensure that there will be no ''gap'' during the transition from the current voluntary reliability model to a mandatory system in which Reliability Standards are enforced by the ERO and Regional Entities. In the long run, we propose to make the Regional Entities responsible, through delegation by the ERO, for the functions currently performed by the regional reliability organizations. As part of this change, the delegation agreements to the Regional Entities should be modified to bind the Regional Entities to assume these duties and responsibility for noncompliance. In addition, the Reliability Standards should be modified to apply through the Functional Model, to the users, owners and operators of the Bulk-Power System that are responsible for providing information.[78]

159. We continue to believe that this is a reasonable interim measure, and note that EEI and others support this approach. To ensure that the ERO properly and timely addresses this matter, we direct the ERO to submit an informational filing within 90 days of the Final Rule that describes its plan and schedule for developing both an interim and long-term resolution based upon the above direction.

160. In response to the Commission's inquiry in the NOPR, commenters identify a number of possible continuing roles for regional reliability organizations. Such activities are beyond the scope of this proceeding. Clearly, any such role must be limited to non-statutory functions. Some commenters suggest that regional reliability organizations may have a role in developing voluntary criteria. Regional reliability organizations should not develop voluntary criteria that address the same or similar matters as mandatory and enforceable Reliability Standards, because that is the responsibility of the Regional Entities.[79]

D. Mandatory Reliability Standards

1. Legal Standard for Approval of Reliability Standards

161. The NOPR explained that section 215(d)(2) of the FPA states that the Commission may approve a Reliability Standard if it determines that it is just, reasonable, not unduly discriminatory or preferential and in the public interest. Further, Order No. 672 laid out a series of factors it would consider when assessing whether to approve or remand a Reliability Standard.[80]

162. In response to NERC's suggestion that a proposed Reliability Standard developed through its open and inclusive process is assured to be ''just, reasonable, and not unduly discriminatory or preferential,'' the NOPR explained that:

> While an open and transparent process certainly is extremely important to the overall success of implementing section 215 of the FPA, an evaluation of any proposed Reliability Standard must focus primarily on matters of substance rather than procedure. We will, therefore, review each Reliability Standard in addition to the process through which it was approved by NERC to ensure that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[81]

163. Further, with regard to NERC's ''benchmarks'' for evaluating a proposed Reliability Standard,[82] the Commission explained that it would not be constrained by such benchmarks in approving or remanding a proposed Reliability Standard. Rather, Order No. 672 identified factors that the Commission will consider when determining whether a proposed

[76] Order No. 672 at P 654.

[77] EOP–007, MOD–011, MOD–013, MOD–014, MOD–015, MOD–024, MOD–025, PRC–002, PRC–003, PRC–006, PRC–012, PRC–013, PRC–014, PRC–020, TPL–005 and TPL–006.

[78] NOPR at P 57 (footnotes omitted).

[79] *See ERO Certification Order* at P 281.

[80] Order No. 672 at P 262, 321–37.

[81] NOPR at P 74.

[82] *Id.* at P 9–12. The benchmarks are: applicability, purpose, performance requirements, measurability, technical basis in engineering and operations, completeness, consequences for noncompliance, clear language, practicality, and consistent terminology.

Reliability Standard satisfies the statutory requirements.

a. Comments

164. NERC states that 83 of the Reliability Standards are ''just, reasonable, not unduly discriminatory or preferential, and in the public interest,'' and should therefore be approved and made effective as mandatory Reliability Standards. NERC believes that, by following NERC's Reliability Standards development process, a Reliability Standard should meet the requirement that a standard be ''just, reasonable, not unduly discriminatory or preferential.'' Further, NERC asserts that, by filing with the Commission the written record of development for each Reliability Standard, NERC has given the Commission strong evidence that those 83 Reliability Standards are just, reasonable, and not unduly discriminatory or preferential.

165. NERC states that the requirement that a Reliability Standard be ''in the public interest'' provides the Commission with broad discretion to review and approve a Reliability Standard. According to NERC, implicit in the ''public interest'' test is that a Reliability Standard is technically sound and ensures an adequate level of reliability, and that the Reliability Standards provides a comprehensive and complete set of technically sound requirements that establish an acceptable threshold of performance necessary to ensure reliability of the Bulk-Power System. NERC states that it believes that approving those 83 Reliability Standards as enforceable as NERC begins operating as the ERO meets this objective and will achieve an adequate level of reliability as required by law. NERC asserts that adopting fewer of the Reliability Standards would both create potential reliability risks and communicate that some aspects of reliability are not viewed as important enough to be the subject of mandatory and enforceable Reliability Standards under the FPA.

166. FirstEnergy states that each proposed standard should be reviewed against the following criteria: (1) Clarity; (2) technical means to comply; (3) practicability; (4) consistency and (5) costs.

b. Commission Determination

167. The Commission agrees with NERC that an open and transparent process is important in implementing section 215 of the FPA and developing proposed mandatory Reliability Standards. However, in Order No. 672, the Commission rejected the presumption that a proposed Reliability Standard developed through an ANSI-certified process automatically satisfies the statutory standard of review.[83] The Commission reiterates that simply because a proposed Reliability Standard has been developed through an adequate process does not mean that it is adequate as a substantive matter in protecting reliability. We will, therefore, review each Reliability Standard to ensure that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, giving due weight to the ERO.

168. In response to FirstEnergy, the Commission has already laid out the factors against which to review a Reliability Standard, as well as other considerations.[84] The Commission has no need to revisit this issue.

2. Commission Options When Acting on a Reliability Standard

169. In the NOPR, the Commission proposed that, for this rulemaking, it would take one of four actions with regard to each proposed Reliability Standard: (1) Approve; (2) approve as mandatory and enforceable; and direct modification pursuant to section 215(d)(5); (3) request additional information; or (4) remand. In fact, the NOPR did not propose to remand any proposed Reliability Standard.[85]

170. With regard to the second category, the Commission explained that it would take two separate and distinct actions under the statute. First, pursuant to section 215(d)(2) of the FPA, the Commission would approve a proposed Reliability Standard, which would be mandatory and enforceable upon the effective date of the Final Rule. Second, the Commission would direct NERC to submit a modification of the Reliability Standard to address specific issues or concerns identified by the Commission pursuant to section 215(d)(5) of the FPA.

171. With regard to the third category, ''request additional information,'' the NOPR explained that some Reliability Standards do not contain sufficient information to enable the Commission to propose a disposition. For those Reliability Standards, the Commission identified the needed information, and proposed not to approve or remand these Reliability Standards until all the relevant information is received. As an example, the NOPR explained that many of the fill-in-the-blank standards would not be approved or remanded until the Commission had received all the necessary information.

a. Comments

172. Most commenters generally support the Commission's proposal to have four courses of action it may take on a Reliability Standard. However, Xcel has concerns about the legality of approving many of the proposed Reliability Standards as mandatory but, at the same time, ordering the ERO to make specific modifications to them. According to Xcel, section 215(d) does not expressly create this ''approve but modify'' option. To the contrary, section 215(d)(4) suggests that the Commission should remand to the ERO a standard that it disapproves ''in whole or in part.''

173. While many commenters support the Commission proposal to approve certain Reliability Standards as mandatory and enforceable; and direct NERC to modify them pursuant to section 215(d)(5), they are concerned that the Commission's directives to modify certain Reliability Standards are too prescriptive.[86] They contend that, in prescribing particular requirements, metrics, or specific language to be used, the Commission is setting the Reliability Standard outside the open Reliability Standards development process and not giving due weight to the ERO under section 215 of the FPA. NRECA, for example, argues there is a major distinction between (a) requiring a Reliability Standard to address a specific matter and (b) requiring (as opposed to suggesting) a specific Reliability Standard or requiring a reliability matter to be addressed in a specific way. These commenters ask that the Final Rule state that a directive to improve a Reliability Standards be in the form of an objective to be achieved or concern or deficiency to be resolved within the Reliability Standard, rather than a particular requirement, metric, or specific language to be used.

174. Many commenters request that the Commission require that changes to any Reliability Standard be made through NERC's Reliability Standard

[83] Order No. 672 at P 338.

[84] *Id.* at P 262, 321–37. (A proposed Reliability Standard must: (1) Provide for the Reliable Operation of Bulk-Power System facilities; (2) be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal; (3) be clear and unambiguous regarding what is required and who is required to comply; (4) clearly state the possible consequences for violating the proposed Reliability Standard; (5) include a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard; (6) achieve its reliability goal effectively and efficiently; (7) not reflect the ''lowest common denominator.'')

[85] NOPR at P 78–82.

[86] *See, e.g.*, NERC, Entergy, EEI, APPA, National Grid, NRECA, TAPS, ISO–NE and Duke.

development procedure.[87] NERC states that there are areas where the Commission proposes a specific directive on a particular Reliability Standard that is well beyond the bounds of current utility practice. According to NERC, these recommendations are often derived from the Staff Preliminary Assessment or are based on a limited number of comments to that assessment. NERC anticipates that the issue of concern with respect to these Reliability Standards will be addressed, but the results may be somewhat different than anticipated by the Commission. Similarly, EEI and Progress state that NERC should not pre-determine the outcome of the Reliability Standard development procedure in response to the Commission's guidance. Ontario IESO states that the Commission should allow its detailed input on the proposed Reliability Standards to be considered through Reliability Standards development process.

175. According to EEI, NERC should be permitted to provide, if the Commission's guidance for modification of a proposed Reliability Standard is not adopted in the Reliability Standard development procedure, an explanation for that outcome when it submits the modified standard to the Commission for approval. Constellation asks the Commission to clarify that, if the ERO Reliability Standards development process does not result in a Reliability Standard that includes the Commission's proposed modifications, the existing Reliability Standard would remain in effect until such time as NERC proposes and the Commission approves a different Reliability Standard (approved through the Reliability Standards development process).

176. Manitoba and Northwest Requirements Utilities disagree with the Commission's proposal to approve certain Reliability Standards and, separately, direct NERC to make modifications. Some commenters, such as California PUC, Northwest Requirements Utilities and SMA state that the users, owners and operators of the Bulk-Power System should not be expected to comply with Reliability Standards that are not finalized or need modification. Northwest Requirements Utilities contends that complete and clear Reliability Standards and requirements are necessary to fair enforcement, particularly if monetary sanctions may apply. Manitoba and California PUC state that approving Reliability Standards that still require modification would lead to differing interpretations of the Reliability Standards and confusion.

177. CEA asserts that the proposed directives to modify certain Reliability Standards, while not remands, reflect engagement in the standards-setting process that may interfere with the ERO's ability to effectively function as an international body. For example, Manitoba states that the Commission's proposed modifications without industry input may unintentionally place Manitoba in a position where it must recommend that the Government of Manitoba disallow the Commission's prescribed modifications to several NERC Reliability Standards, thus creating discrepancies between Reliability Standards across North America.

178. FirstEnergy agrees with the Commission's rejection of the concept of ''conditional approval'' in favor of approve but modify to ensure that enforceable standards are in place. However, it asks that the Commission consider waiving, or at least substantially reducing, penalties for violations of some enforceable, but yet-to-be-completed or modified Reliability Standards because compliance with such Reliability Standards may prove difficult to determine. FirstEnergy therefore suggests that the Commission exercise due discretion in enforcing affected Reliability Standards, especially where the Commission itself has found that a standard is incomplete or ambiguous. International Transmission agrees that in instances where the Commission has proposed material changes to a Reliability Standard and its associated measurements, risk factors and Levels of Non-Compliance, it may be appropriate for the ERO to exercise enforcement discretion on a case-by-case basis.

179. SoCal Edison is concerned that entities may not have an opportunity to (1) review the Reliability Standards that are adopted in the Final Rule and (2) make any necessary changes in their operating or planning practices in order to incorporate differences between the NOPR and the Final Rule. SoCal Edison recommends the Commission specifically state the ''effective date'' for compliance with each Reliability Standard in its Final Rule. SoCal Edison is concerned because some standards have a proposed NERC ''effective'' date after the Final Rule.

180. Northern Indiana states it is concerned how a June 2007 effective date will impact electric system reliability during the critical summer peak demand period, particularly given the many problems with the standards that have been identified. Northern Indiana believes the Commission's current actions may, in the near term, create a lower probability of success in achieving the Commission's stated objectives. Northern Indiana suggests that the traditional summer peak season is not a good time to implement broad changes in electric system operations, procedures and protocols.

181. NRECA states it is concerned by the NOPR's efforts to establish specific one and three year time frames for resolution of various matters. It states that the Commission is authorized to comment on priorities and suggest timing, it must allow NERC to follow its ANSI-certified Reliability Standards development process.

182. NERC requests that the Commission provide a directive in the Final Rule requiring NERC to address both the Commission's concerns with the existing Reliability Standards and all comments filed in this rulemaking proceeding suggesting specific improvements to the Reliability Standards. NERC states that if the Commission acts on the views expressed on a specific Reliability Standard by an individual commenter in this rulemaking, it may encourage others to avoid participating in the NERC process and instead wait until a proposed new or modified Reliability Standard reaches the Commission approval stage to express their views on the standards. NERC states that no commenter should be entitled to have its comments on a specific Reliability Standard resolved by the Commission in this rulemaking proceeding.

183. NERC maintains that referring all comments to the NERC Reliability Standards development process for resolution is consistent with NERC's obligation to facilitate an open stakeholder process for the development of Reliability Standards. NERC asserts that it gives fair consideration to all comments and objections on a proposed new or revised Reliability Standard and such comments are either resolved to the satisfaction of the commenter, or reasons are stated as to why the commenter's recommendation should not be adopted.

b. Commission Determination

184. The Commission affirms the four possible courses of action that it will take with regard to each proposed Reliability Standard: (1) Approve; (2) approve as mandatory and enforceable; and direct modification pursuant to section 215(d)(5); (3) request additional information; or (4) remand. Each course of action is justified and has a sound basis in the statute. Xcel questions the

[87] *See, e.g.*, NERC, EEI, ELCON, CEA, NYSRC, TVA, LPPC, NPCC, Ontario IESO, Constellation, Progress and Dynegy.

legality of the second option above, which it incorrectly equates to ''conditional acceptance.'' Rather, as explained in the NOPR,[88] the Commission is taking two independent actions, both authorized by the statute. First, we are exercising our authority, contained in section 215(d)(2) of the FPA, to approve a proposed Reliability Standard. Second, we are directing the ERO to submit a modification of the Reliability Standard to address specific issues or concerns identified by the Commission, pursuant to section 215(d)(5) of the FPA.[89] Accordingly, we reject Xcel's contention and adopt the NOPR proposal on this matter.

185. With regard to the many commenters that raise concerns about the prescriptive nature of the Commission's proposed modifications, the Commission agrees that a direction for modification should not be so overly prescriptive as to preclude the consideration of viable alternatives in the ERO's Reliability Standards development process. However, in identifying a specific matter to be addressed in a modification to a Reliability Standard, it is important that the Commission provide sufficient guidance so that the ERO has an understanding of the Commission's concerns and an appropriate, but not necessarily exclusive, outcome to address those concerns. Without such direction and guidance, a Commission proposal to modify a Reliability Standard might be so vague that the ERO would not know how to adequately respond.

186. Thus, in some instances, while we provide specific details regarding the Commission's expectations, we intend by doing so to provide useful guidance to assist in the Reliability Standards development process, not to impede it.[90] We find that this is consistent with statutory language that authorizes the Commission to order the ERO to submit a modification ''that addresses a specific matter'' if the Commission considers it appropriate to carry out section 215 of the FPA.[91] In the Final Rule, we have considered commenters' concerns and, where a directive for modification appears to be determinative of the outcome, the Commission provides flexibility by directing the ERO to address the underlying issue through the Reliability Standards development process without mandating a specific change to the Reliability Standard. Further, the Commission clarifies that, where the Final Rule identifies a concern and offers a specific approach to address the concern, we will consider an equivalent alternative approach provided that the ERO demonstrates that the alternative will address the Commission's underlying concern or goal as efficiently and effectively as the Commission's proposal.

187. Consistent with section 215 of the FPA and our regulations, any modification to a Reliability Standard, including a modification that addresses a Commission directive, must be developed and fully vetted through NERC's Reliability Standard development process. The Commission's directives are not intended to usurp or supplant the Reliability Standard development procedure. Further, this allows the ERO to take into consideration the international nature of Reliability Standards and incorporate any modifications requested by our counterparts in Canada and Mexico. Until the Commission approves NERC's proposed modification to a Reliability Standard, the preexisting Reliability Standard will remain in effect.

188. We agree with NERC's suggestion that the Commission should direct NERC to address NOPR comments suggesting specific new improvements to the Reliability Standards, and we do so here. We believe that this approach will allow for a full vetting of new suggestions raised by commenters for the first time in the comments on the NOPR and will encourage interested entities to participate in the ERO Reliability Standards development process and not wait to express their views until a proposed new or modified Reliability Standard is filed with the Commission. As noted throughout the standard-by-standard analysis that follows, various commenters provide specific suggestions to improve or otherwise modify a Reliability Standard that address issues not raised in the NOPR. In such circumstances, the Commission directs the ERO to consider such comments as it modifies the Reliability Standards during the three-year review cycle contemplated by NERC's Work Plan through the ERO Reliability Standards development process. The Commission, however, does not direct any outcome other than that the comments receive consideration.

189. We disagree with commenters, such as Xcel, suggesting that the Commission should not approve Reliability Standards that we require NERC to modify. The Commission is only approving those Reliability Standards that it has determined to be just, reasonable, not unduly discriminatory or preferential, and in the public interest. As discussed more fully in the discussion of the individual Reliability Standards, we have determined that each approved Reliability Standard is sufficiently clear and independently enforceable. Because we believe that these Reliability Standards are enforceable as written, the Commission will not exempt them from enforcement.

190. The Commission disagrees with Northern Indiana that the Reliability Standards should not be implemented in summer of 2007.[92] Most or all users, owners and operators of the Bulk-Power System have participated in NERC's voluntary reliability regime for years and are familiar with the proposed Reliability Standards. Others have had notice of the Reliability Standards since they were filed by NERC in April 2006. We are not persuaded that making Reliability Standards enforceable, most of which were being complied with on a voluntary basis, will require broad changes in electric system operations, procedures and protocols. Therefore, we do not see any reason to further delay implementation of the mandatory Reliability Standards.

191. In response to SoCal Edison, Reliability Standards will become effective the latter of the effective date of this Final Rule or the ERO's proposed NERC effective date. The Commission disagrees with SoCal Edison that users, owners and operators of the Bulk-Power System will not have an opportunity to review the Reliability Standards that are adopted in the Final Rule and incorporate differences between the NOPR and the Final Rule into their operating practices. The Reliability Standards approved in this Final Rule are approved as proposed by the ERO. No changes will be made immediately based on the Commission's direction to modify those Reliability Standards. Any modifications will be developed through the ERO's Reliability Standards development process and should have a

[88] *See* NOPR at P 79–80.

[89] 16 U.S.C. 824o(d)(5) (''[t]he Commission * * * may order the Electric Reliability Organization to submit to the Commission a proposed Reliability Standard or modification to a Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Reliability Standard appropriate to carry out this section.'').

[90] Moreover, in the NOPR, the Commission first discussed in detail its substantive concerns regarding a particular proposed Reliability Standard and, to provide greater clarity regarding the Commission proposal, then summarized the proposed findings and modifications. It appears that such summaries of broader and fuller discussions led to misunderstandings of the NOPR proposals.

[91] 16 U.S.C. 824o(d)(5).

[92] See discussion below regarding the Trial Period, section II.D.4.

proposed effective date that will take into account any time needed for users, owners and operators of the Bulk-Power System to incorporate the necessary changes. Therefore, there is no need for any entity to make any changes based on differences between the NOPR and the Final Rule.

192. NRECA's assertion that the Commission should not establish timelines to resolve matters is a collateral attack on Order No. 672. In that order, the Commission adopted its regulations to provide that the Commission, when ordering the ERO to submit to the Commission a proposed Reliability Standard or proposed modification to a Reliability Standard that addresses a specific matter, may order a deadline by which the ERO must submit a proposed or modified Reliability Standard.[93]

3. Prioritizing Modifications to Reliability Standards

193. As discussed above, the Commission proposed to approve certain Reliability Standards and, as a separate action, proposed to direct the ERO to modify many of the same Reliability Standards pursuant to section 215(d)(5) of the FPA. In the NOPR, the Commission recognized that it is not reasonable to expect the modification of such a substantial number of Reliability Standards in a short period of time. Thus, the NOPR provided guidance on the prioritization of needed modifications.[94]

194. The NOPR proposed that NERC first focus its resources on modifying those Reliability Standards that have the largest impact on near-term Bulk-Power System reliability, including many of the proposed modifications that reflect Blackout Report recommendations. Further, the Commission identified a group of Reliability Standards that it believes should be given the highest priority by the ERO based on the above guidance.[95] The NOPR explained that the list is not meant to be exclusive or inflexible and solicited ERO and commenter input. The NOPR proposed that NERC address the ''high priority'' modifications within one year of the effective date of the Final Rule.

195. In addition, the NOPR proposed that the ERO promptly address certain proposed modifications that are not necessarily identified as ''high priority'' but may be addressed in a relatively short time frame because the proposed modifications are relatively minor or ''administrative'' in nature. The NOPR further proposed that the ERO develop a detailed, comprehensive Work Plan to address all of the modifications that are directed pursuant to a Final Rule. The Work Plan would take a staggered approach and complete all the proposed modifications within either two or three years from the effective date of the Final Rule.

196. As noted above, on December 1, 2006, NERC submitted its Work Plan as an informational filing. According to the Work Plan, NERC will revise the existing Reliability Standards to incorporate improvements. A total of 31 different projects will be completed over a three-year period.[96] Some of the projects address revising a single Reliability Standard. The largest project includes revising 19 Reliability Standards focusing on related topics. NERC asserts that grouping the Reliability Standards in this manner will be the most efficient use of the resources and will allow consistency in requirements on related standards. NERC states that the Work Plan incorporates modifications that were proposed in the NOPR, but it will modify its Work Plan to align it with the modifications the Commission orders in the Final Rule. In addition, the Work Plan will remain dynamic as new Reliability Standards are proposed and priorities evolve. The Work Plan will be updated on an annual basis, and more frequently if needed.

197. According to the Work Plan, NERC will periodically report progress and revisions to the Work Plan and timetable to the Commission. NERC's intent is to provide accountability for the revision and development of Reliability Standards, while recognizing it is impossible to have a fixed schedule when working in a consensus-driven process addressing complex technical matters.

a. Comments

198. NERC states that it is pleased that the Commission did not propose specific deadlines in the NOPR for completing the directives to improve the Reliability Standards. NERC requests that the Commission not state specific delivery dates, because developing consensus Reliability Standards on complex technical matters within fixed time frames may not be realistic in all cases. NERC states that it will report the reasons for any delays in the schedule and will work to ensure that no unnecessary delays occur due to lack of attention or effort.

199. NERC expresses concern that the Commission suggests in the NOPR that it may direct some early modifications to the Reliability Standards that appear to provide quick results.[97] According to NERC, because of the procedural requirements of the Reliability Standards development process, this would delay work that is more important. NERC states that it can make such changes quickly for a particular Reliability Standard if there are no other changes to that standard. However, NERC's Work Plan contemplates that almost every Reliability Standard is to be upgraded; modifying each standard in multiple steps would add significant delay.

200. APPA similarly cautions the Commission that the industry does not have unlimited ability to simultaneously reevaluate the Reliability Standards, prepare for NERC's and the Regional Entities' compliance monitoring and enforcement programs, and actually plan and operate their utility systems on a reliable basis. According to APPA, NERC should promptly address the administrative elements of those Reliability Standards that are now at best incomplete, with missing Compliance Measures, Levels of Non-Compliance and Violation Risk Factors. NERC must also deal with the regional fill-in-the-blank standards and criteria that have not yet been submitted to either NERC or to the Commission for review and approval.

201. International Transmission states that the Commission should not direct NERC to make changes to the Reliability Standards within a specific time frame because this would circumvent the Reliability Standard development process. It asks the Commission to instruct the ERO to initiate the Reliability Standards development process in a time frame that would likely result in their presentation to the Commission by a desired date, acknowledging that a revised Reliability Standard may not reach industry consensus and thus not meet the Commission's desired time frame. Further, International Transmission believes that the priority of a Reliability Standard for subsequent modification should be based on the standard's ''Violation Risk Factor.'' Reliability Standards that have the greatest impact on bulk electric system reliability should be addressed first. All high risk requirements should be addressed in the 2007 Work Plan. International Transmission states the addition of Measures and Levels of Non-

[93] *See* 18 CFR 39.5(g).

[94] NOPR at P 85–87.

[95] *Id.* at Appendix D (High Priority List).

[96] Some projects relate to new Reliability Standards that are not before the Commission in the instant rulemaking.

[97] NOPR at P 86.

Compliance is neither minor nor administrative in nature, although designated by the Commission as such and called for an accelerated time period for their addition.

202. MRO recommends that the Commission place a greater emphasis on directing NERC to develop clear and measurable Requirements. If the Requirements are not clear and measurable, the Measures and Levels of Non-Compliance will be fundamentally flawed. MRO also states that there are numerous Requirements that are now part of the Reliability Standards that came from elements of the former NERC Operating Manual that were never intended as Requirements. It believes that this, in part, has created certain difficulties that have resulted in a lack of Measures or Levels of Non-Compliance in the Reliability Standards. MRO provides examples of such difficulties in its comments regarding specific Reliability Standards. MRO suggests grouping each Requirement with its associated Measure and Level of Non-Compliance thus making it clear to the user, owner or operator as to which Requirements, Measures and Levels of Non-Compliance are related thereby reducing confusion.

203. APPA and Alcoa state that the Commission did not give sufficient time for comments on NERC's submitted Work Plan. APPA notes that the Work Plan will have to be revised following issuance of the Final Rule.

b. Commission Determination

204. Given the concerns raised by commenters, the Commission will not adopt the NOPR's proposal to direct some early modifications to the Reliability Standards. We agree with NERC that modifying each Reliability Standard first to address administrative concerns, then sending it back to the Reliability Standards development process to address any modifications directed by the Commission or requested by stakeholders, might lead to an unacceptable delay.

205. While the Commission agrees with International Transmission that a good starting point for prioritizing modifications to a Reliability Standard could be based on the Reliability Standard's ''Violation Risk Factor,'' the Commission will not mandate that the ERO do so. The ERO should take into account the views of its stakeholders, including the concerns raised in this proceeding by APPA, International Transmission and MRO, in revising its Work Plan following issuance of this Final Rule.

206. In Order No. 890, the Commission directed public utilities, working through NERC, to modify the ATC-related Reliability Standards within 270 days of publication of Order No. 890 in the **Federal Register**.[98] Our action there affects approximately nine MOD Reliability Standards and one FAC Reliability Standard that are before us in this proceeding. The ERO must submit its revised Work Plan within 90 days of the effective date of the Reliability Standards approved in this order as an informational filing to: (1) Reflect modification directives contained in the Final Rule; (2) include the timeline for completion of ATC-related Reliability Standards as ordered in Order No. 890 and (3) account for the views of its stakeholders, including those raised in this proceeding.

207. The Commission disagrees with NERC that we should not set specific delivery dates. A Work Plan with specific target dates will provide a valuable tool and incentive to timely address the modifications directed in this Final Rule. We note that the ERO previously prepared and submitted to the Commission for informational purposes one iteration of such a Work Plan that identifies target dates for the modification of Reliability Standards. Accordingly, we direct the ERO to submit as an informational filing, within 90 days of the effective date of this Final Rule, a Work Plan that identifies a plan for addressing the modifications to the Reliability Standards directed by the Commission in this Final Rule and a schedule with delivery dates for completing such modifications. The ERO should make every effort to meet such delivery dates. However, we understand that there may be certain cases in which the ERO is not able to meet a Commission's deadline. In those instances, the ERO must inform the Commission of its inability to meet the specified delivery date and explain why it will not meet the deadline and when it expects to complete its work.

4. Trial Period

208. NERC and some commenters to the Staff Preliminary Assessment recommended that the Commission establish a ''trial period'' during which time the ERO would determine, but not collect, monetary penalties. In the NOPR, the Commission expressed concern that a trial period that commences with the effective date of mandatory and enforceable Reliability Standards may interfere with their being made effective by summer 2007. Thus, the NOPR did not propose a trial period.[99]

209. However, the Commission recognized that there are entities that have not historically participated in the pre-existing voluntary reliability system (including some relatively small entities) that may not be familiar with what is required for compliance with the proposed mandatory Reliability Standards. For such entities, the NOPR proposed that the ERO and Regional Entities use their discretion in imposing penalties on such entities for the first six months the Reliability Standards are in effect. However, the Commission, the ERO and the Regional Entities would still retain the authority to impose penalties on such entities if warranted by the circumstances.

a. Comments

210. Most commenters request that the Commission reconsider the proposal to reject a trial period during which the Reliability Standards are mandatory and enforceable but during which penalties would not be assessed for violating a Reliability Standard.[100] EEI, for example, notes that the compliance enforcement program and the delegation agreements have not yet been approved by the Commission and there may be a short time between their approval and the projected start date for enforcing the Reliability Standards. Therefore, commenters generally state that a trial period is appropriate to ensure that the compliance monitoring and enforcement processes work as intended and that entities have time to implement new processes, such as required data systems; after June 2007, commenters generally state that NERC and the Regional Entities would be able to require remedial actions where there is an immediate actual or potential risk to reliable interconnected operations. Further, some state that a trial period would allow NERC to resolve issues with unfinished standards or ambiguous standards for which the Commission has directed improvements. If the Commission rejects a six-month trial period, several entities, such as EEI, PG&E, Xcel and NYSRC, request that the Commission extend NERC's discretionary enforcement to all entities, not just those new to the Reliability Standards.

211. NPCC essentially agrees with the Commission that there should be no trial period, but if the definition of Bulk-Power System is substantially altered to

[98] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266(March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007) at P 223.

[99] *Id.* at P 92–93.

[100] *See, e.g.*, EEI, APPA, TAPS, EPSA, CAISO, Bonneville, California PUC, Cleveland, Otter Tail, Northwest Requirements Utilities, TVA and SMA.

draw in a broad range of entities that have not traditionally been subject to pre-existing reliability standards, a transition period is appropriate to bring them into compliance. Where a Reliability Standard has missing or incomplete compliance measures, ATC states that the Commission should make these standards mandatory to avoid gaps, but not assess monetary penalties for non-compliance. ATC agrees with the Commission that the new mandatory reliability regime should be operational by June 2007, noting that it has been over three years since the August 2003 Blackout and over a year since EPAct 2005 was enacted.

212. Several entities state that the Commission's proposal to allow the ERO and Regional Entities discretion in setting penalties does not go far enough, even if it is applied to all users, owners and operators of the Bulk-Power System. For example, SERC maintains that its proposed delegation agreement and the NERC Compliance Monitoring and Enforcement Program may not allow discretion in imposing penalties.

213. NERC states that it understands and supports the importance the Commission places on the ERO having the ability to impose a financial penalty if a Bulk-Power System user, owner or operator violates a mandatory Reliability Standard that is in effect, especially for egregious behavior. However, NERC continues to maintain that a validation period for the compliance process and the calculation of penalties is important and proposes a modified approach to that taken by the Commission. NERC asks the Commission to authorize NERC and the Regional Entities to exercise discretion to calculate financial penalties, but not collect them in the case of most violations through December 31, 2007. At the same time it asks the Commission to specify that in a situation in which an entity violates a clear and well-understood Reliability Standard that causes a significant disturbance on the Bulk-Power System, or in the face of other aggravating circumstances such as repeated or intentional violations, the ERO and the Regional Entities would have the authority and responsibility to hold the offending entity fully accountable for the violation, by the assessment of financial penalties.

214. NERC states that this alternative approach is supported by the newness of the compliance enforcement program, the Sanctions Guidelines and the penalty matrix, and the Violation Risk Factors, which have not been approved by the Commission. Further, NERC claims that initiating operations under mandatory Reliability Standards with the collection of penalties as the rule rather than the exception may increase the risk of numerous legal challenges occurring in the early stages of implementing mandatory Reliability Standards, whereas NERC would expect a rapid decline in such challenges after its proposed validation period. In a reply comment, Xcel supports NERC's proposed approach.

215. If the Commission rejects NERC's proposed modified approach, NERC asks that it and the Regional Entities be given broad discretion in setting penalties during this time period and that this discretion not be limited to small entities or those who are new to Reliability Standards. Avista/Puget also urges the Commission, the ERO and the Regional Entities to exercise enforcement discretion more broadly than proposed in the NOPR. Penalties should be waived for an initial period in several situations, including where a Reliability Standard is applied based on new or different interpretations.

216. Some commenters request that the Commission grant a longer trial period in certain cases. For instance, TANC believes that for smaller entities the Commission should, at a minimum, adopt a trial period of at least one year to provide adequate time to evaluate and comply with the new mandatory Reliability Standards. Bonneville and NPCC suggest that, for Reliability Standards that have an annual reporting requirement, the compliance cycle should start on June 2007 so that a Reliability Standard that relies on data reporting back into the prior year should have an initial compliance measurement date of June 2008. AMP-Ohio states that the Commission's proposal does not go far enough and suggests a ''ramp-up'' period for entities that are new to standards, through and including the entity's first compliance audit or, if the Commission rejects this proposal, the Commission should extend the trial period from six to twelve months. Reliant also advocates a phase-in of penalties over six to twelve months, with an increasing scale of penalties over time.

217. Portland General and Tacoma request that the Commission institute a one-year trial period to allow the industry time to finalize the language of the mandatory Reliability Standards and to allow users, owners and operators time to adapt to the final language. For any Reliability Standard that requires modification, Tacoma requests that the Commission provide a six-month trial period beyond the date when the Reliability Standard is completed. Bonneville asks that the Commission extend the trial period for Reliability Standards that have missing or ambiguous measures or severity levels until those issues are resolved. National Grid states that enforcement discretion should not be limited in scope or duration and should be extended to any situation in which a Reliability Standard is applied in a novel manner, including when a Reliability Standard is interpreted for the first time.

218. PG&E asserts that NERC and the Regional Entities should have discretion in imposing fines for violations of Reliability Standards during a transition period. Where an entity shows a good faith effort to comply with a new or changed Reliability Standard promptly and thoroughly, NERC and/or the Regional Entity should be permitted to consider those efforts in assessing fines. PG&E suggests a transition period of three to six months. Without such discretion, entities may be pressured to implement Reliability Standards hastily and inadequately. PG&E also notes that some entities in WECC have voluntarily participated in WECC's enforcement program. The new regime entails procedural and substantive changes. Entities that have complied voluntarily should not be penalized by denying them an opportunity to adjust.

219. WECC states that it continues to believe that a trial period of more than six months is appropriate, but it is not requesting that the Commission revisit its decision on this issue. WECC asks that Regional Entities have somewhat greater flexibility in monitoring and enforcing compliance during the initial period of implementation. According to WECC, the Commission should recognize that, in the early stages of implementation, penalties should be reserved for clear situations where Registered Entities are refusing to comply. Unreasonably harsh enforcement in the early stages of implementation may damage the current level of reliability by diverting resources away from developing solutions in order to avoid fines and support litigation. This flexibility should continue beyond six months after the effective date, if necessary, for those Reliability Standards requiring modification, until such modifications have become effective.

220. According to WECC, it is extremely important that United States, Canadian and Mexican authorities enforce their respective standards within WECC in a way that avoids conflicting obligations. WECC thus suggests that the Commission grant WECC substantial discretion to focus on education and facilitation of compliance with NERC Reliability Standards while

it seeks to promote consistent enforcement internationally.

b. Commission Determination

221. The Commission adopts its proposal not to institute a formal trial period. As we explained in the NOPR, a trial period is inconsistent with mandatory and enforceable Reliability Standards taking effect in a timely manner.[101] The Commission's overriding concern is the reliability of the Bulk-Power System, and mandatory and enforceable Reliability Standards becoming effective in a timely manner are essential to ensuring the reliability of the Bulk-Power System. Accordingly, the Commission will not adopt a formal trial period.

222. The Commission is, however, also cognizant of commenters' concerns. In the NOPR, the Commission proposed that the ERO and Regional Entities use their enforcement discretion in imposing penalties on entities that historically had not participated in the pre-existing voluntary reliability regime, although authority to impose a penalty on such an entity would be retained ''if warranted by the circumstances.'' [102] In light of commenters'' concerns, including the fact that there are new aspects to the Reliability Standards and the proposed compliance program that will apply to all users, owners and operators of the Bulk-Power System, the Commission directs the ERO and Regional Entities to focus their resources on the most serious violations during an initial period through December 31, 2007. This thoughtful use of enforcement discretion should apply to all users, owners and operators of the Bulk-Power System, and not just those new to the program as originally proposed in the NOPR. This approach will allow the ERO, Regional Entities and other entities time to ensure that the compliance monitoring and enforcement processes work as intended and that all entities have time to implement new processes.

223. By directing the ERO and Regional Entities to focus their resources on the most serious violations through the end of 2007, the ERO and Regional Entities will have the discretion necessary to assess penalties for such violations, while also having discretion to calculate a penalty without collecting the penalty if circumstances warrant. Further, even if the ERO or a Regional Entity declines to assess a monetary penalty during the initial period, they are authorized to require remedial actions where a Reliability Standard has been violated. Furthermore, where the ERO uses its discretion and does not assess a penalty for a Reliability Standard violation, we encourage the ERO to establish a process to inform the user, owner or operator of the Bulk-Power System of the violation and the potential penalty that could have been assessed to such entity and how that penalty was calculated. We leave to the ERO's discretion the parameters of the notification process and the amount of resources to dedicate to this effort. Moreover, the Commission retains its power under section 215(e)(3) of the FPA to bring an enforcement action against a user, owner or operator of the Bulk-Power System.

224. The Commission believes that the goal should be to ensure that, at the outset, the ERO and Regional Entities can assess a monetary penalty in a situation where, for example, an entity's non-compliance puts Bulk-Power System reliability at risk. Requiring the ERO and Regional Entities to focus on the most serious violations will allow the industry time to adapt to the new regime while also protecting Bulk-Power System reliability by allowing the ERO or a Regional Entity to take an enforcement action against an entity whose violation causes a significant disturbance. Our approach strikes a reasonable balance in ensuring that the ERO and Regional Entities will be able to enforce mandatory Reliability Standards in a timely manner, while still allowing users, owners and operators of the Bulk-Power System time to acquaint themselves with the new requirements and enforcement program. In addition, our approach ensures that all users, owners and operators of the Bulk-Power System take seriously mandatory, enforceable reliability standards at the earliest opportunity and before the 2007 summer peak season.

225. National Grid, among others, states that the Commission should allow enforcement discretion on an ongoing basis, for example, when the ERO or a Regional Entity interprets a Reliability Standard for the first time. The Commission agrees that, separate from our specific directive that all concerned focus their resources on the most serious violations during an initial period, the ERO and Regional Entities retain enforcement discretion as would any enforcement entity. Such discretion, in fact, already exists in the guidelines; as we stated in the *ERO Certification Order*, the Sanction Guidelines provide flexibility as to establishing the appropriate penalty within the range of applicable penalties.[103]

5. International Coordination

226. In response to concerns regarding international coordination of action on proposed Reliability Standards, the Commission reaffirmed its recognition of the importance of international coordination, previously discussed in both Order No. 672 [104] and the *ERO Certification Order.*[105]

a. Comments

227. Ontario IESO agrees with the Commission ''that NERC's development of a coordination process, together with the existing means of communications and coordination such as the United States—Canada Bilateral Electric Oversight Group will provide the necessary mechanisms for international coordination'' and supports the coordination process proposed by NERC in its October 18, 2006 filing in Docket No. RR06–1–003.[106]

228. EEI and National Grid state that it is not sufficient to coordinate remands through NERC alone because both the Commission and Canadian provincial authorities have the ultimate say in approving applicable Reliability Standards. They advocate that the various regulators commit to coordinate through a formal mechanism, such as a memorandum of understanding. According to EEI, the Commission should coordinate with its international counterparts when directing modifications to Reliability Standards to ensure that the resulting Reliability Standards are uniform to the greatest extent possible. NPCC adds that the Commission should coordinate with its international counterparts when proposing to hold, remand or reject a proposed Reliability Standard to avoid inconsistencies in Reliability Standards application.

229. National Grid states that, where similar interpretations and modifications to Reliability Standards are not adopted by the provincial authorities in Canada, there is potential for conflicting requirements for interconnected facilities. The Alberta ESO is also concerned that, due to regulatory/legislative requirements and industry structures in Canada, some of the Reliability Standards may not be implemented as they are written.

[101] NOPR at P 92.

[102] *Id.* at P 93.

[103] *ERO Certification Order* at P 451.

[104] *See* Order No. 672 at P 400.

[105] *ERO Certification Order* at P 286.

[106] Compliance Filing of the North American Electric Reliability Council and the North American Electric Reliability Corporation Addressing Non-Governance Issues, Appendix 3C, Docket No. RR06–1–000 (October 18, 2006).

Therefore it requests that the Commission require that the international coordination process include a provision where variances are identified by these international governmental authorities to minimize the possibility of a governmental authority remanding a Reliability Standard. According to Alberta ESO, while the goal should be consistent, North America-wide Reliability Standards, there will be instances where this is not achievable.

230. WIRAB advises that some Canadian provinces or Mexican authorities may approve NERC-proposed Reliability Standards with changes or modifications. It is important to allow minor variations across such jurisdictions to minimize the possibility of a governmental authority remanding a Reliability Standard. According to WIRAB, the goal should be a consistent system throughout North America with enough flexibility for some jurisdictional variation when uniformity is not immediately possible.

b. Commission Determination

231. In the *January 2007 Compliance Order*, the Commission stated that, to minimize the possibility of a governmental authority directing a remand, it seemed appropriate for such governmental authorities to have an opportunity to provide NERC with input prior to its filing for governmental approval of a proposed Reliability Standard.[107] In that order, the Commission agreed with NERC's proposal to facilitate informal conferences to provide an opportunity for governmental authorities to consult with NERC and stakeholder representatives regarding Reliability Standard development work-plans, objectives and priorities, and emerging Reliability Standards.[108] While we did not initiate a formal mechanism for coordination as EEI and National Grid now suggest, we did state that we anticipate that the Commission and counterpart governmental authorities in Canada and Mexico will convene regular meetings to coordinate on issues relating to reliability. We reaffirm that approach as an appropriate framework for addressing matters of international coordination in the context of continent-wide Reliability Standards.

232. We agree with Alberta ESO and WIRAB that the goal should be consistent, North America-wide Reliability Standards, but that this may not be achievable in all instances. For example, in this rulemaking the Commission is approving several regional differences in Reliability Standards; in the United States, NERC identifies regional variations by submitting them to the Commission in the form of a Reliability Standard.[109]

233. In response to WIRAB, if a governmental authority in Canada or Mexico requests that NERC modify a continent-wide Reliability Standard rather than create a regional variance, NERC must submit any revised Reliability Standard to the Commission. The Commission will then have an opportunity to review the proposed revised Reliability Standard, taking into account the request of the foreign governmental authority.

E. Common Issues Pertaining to Reliability Standards

1. Blackout Report Recommendation on Liability Limitations

234. In the NOPR, the Commission stated that the Blackout Report recommendations, many of which address key issues for assuring Bulk-Power System reliability, have received international support and represent a well-reasoned and sound basis for action. Thus, in the discussion of a particular proposed Reliability Standard, the NOPR often recognized the merit of a specific Blackout Report recommendation and reaffirmed the reasoning behind such recommendation in proposing to approve, with a proposed directive to modify, a specific Reliability Standard. Further, the Commission indicated that a modification to a proposed Reliability Standard based on a Blackout Report recommendation should receive the highest priority in terms of NERC's Work Plan.[110]

235. The Blackout Report's Recommendation No. 8 recognized that timely and sufficient action to shed load on August 14, 2003, would have prevented the spread of the blackout beyond northern Ohio, and recommended that legislative bodies and regulators should: (1) Establish that operators (whether organizations or individuals) who initiate load shedding pursuant to operational guidelines are not subject to liability suits and (2) affirm publicly that actions to shed load pursuant to such guidelines are not indicative of operator failure.[111]

a. Comments

236. EEI states that the Commission should adopt OATT liability limitations to implement Blackout Report Recommendation No. 8 because compliance with mandatory Reliability Standards may expose transmission operators to liability for actions required by a Reliability Standard; Blackout Report Recommendation No. 8 identified this concern and recommended that legislative bodies and regulators establish that operators who initiate load shedding are not subject to liability. EEI disagrees with the suggestion that the Commission cannot shield operators from liability suits. EEI states that the Commission has the authority under FPA sections 205 and 206 to provide liability protection and has done so for several transmission operators in several cases by approving amendments to open access transmission tariffs providing for liability limitations.[112] However, it notes that the Commission has rejected efforts by other parties to implement similar protections.[113]

b. Commission Determination

237. Consistent with Order No. 890, the Commission does not adopt new liability protections.[114] The Commission does not believe any further action is needed to implement Blackout Report Recommendation No. 8. First, the Task Force found that no further action is needed.[115] Further, the Blackout report indicated that some states already have appropriate protection against liability suits.[116] Finally, in Order No. 888, the Commission declined to adopt a uniform federal liability standard and decided that, while it was appropriate to protect the transmission provider through force majeure and indemnification provisions from damages or liability when service is provided by the transmission provider without negligence, it would leave the determination of liability in other instances to other proceedings.[117] Order

[107] *January 2007 Compliance Order* at P 44.

[108] *Id.*

[109] Order No. 672 at P 296.

[110] NOPR at P 99–100.

[111] Blackout Report at 147

[112] EEI at 16, citing *Southwest Power Pool, Inc.,* 112 FERC ¶ 61,100 (2005); *Midwest Independent Transmission System Operator, Inc.,* 110 FERC ¶ 61,164 (2005); *ISO New England, Inc.,* 106 FERC ¶ 61, 280, *order on reh'g,* 109 FERC ¶ 61,147 (2004).

[113] *Id.,* citing *Southern Company Services, Inc.,* 113 FERC ¶ 61,239 (2005).

[114] Order No. 890 at P 1671–77.

[115] U.S.-Canada Power System Outage Task Force, Final Report on Implementation of Task Force Recommendations at 22 (Oct. 3, 2006), available at *http://www.oe.energy.gov/news/blackout.htm* (''Action Required at Fully Implement Recommendation 8: No further action under this recommendation is needed'').

[116] *Id.* (''In the United States, some state regualtors have informally expressed the view that there is appropriate protection against liability suits for parties who shed load according to approved guidelines.'')

[117] Order No. 888–B, 81 FERC ¶ 61,248 at 62,081 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,*

No. 890 reaffirmed this decision. EEI has offered no arguments that demonstrate that an OATT limit on liability is warranted.

2. Measures and Levels of Non-Compliance

238. The NOPR noted that, according to the Staff Preliminary Assessment, a number of proposed Reliability Standards do not contain Measures [118] or Levels of Non-Compliance,[119] or both. NERC, in its petition, identified 21 Reliability Standards that lack Measures or Levels of Non-Compliance and indicated that it planned to file modified Reliability Standards that include the missing Measures and Levels of Non-Compliance in November 2006. On November 15, 2006, NERC made this filing.

239. In the NOPR, while the Commission recognized the importance of having Measures and Levels of Non-Compliance specified for each Reliability Standard, the Commission also stated that the absence of these two elements is not critical to the determination of whether to approve a proposed Reliability Standard. Rather, the most critical elements of a Reliability Standard are the Requirements, and, if properly drafted, a Reliability Standard may be enforced even in the absence of specified Measures or Levels of Non-Compliance.[120] Thus, the NOPR proposed to approve a Reliability Standard even though it may lack Measures or Levels of Non-Compliance, or where these elements contain ambiguities, provided that the Requirement is sufficiently clear and enforceable. Where a Reliability Standard would be improved by providing missing Measures or Levels of Non-Compliance or by clarifying ambiguities with respect to Measures or Levels of Non-Compliance, the NOPR proposed to approve the Reliability Standard and concurrently direct NERC to modify the Reliability Standard accordingly.

240. The NOPR explained that the common format of NERC's proposed Reliability Standards calls for a ''data retention'' metric. Yet, some proposed Reliability Standards either do not contain a data retention requirement or state that no record retention period applies. In the NOPR, the Commission requested comment on: (1) Whether the retention time periods specified in various Reliability Standards proposed by NERC are sufficient to foster effective enforcement and (2) what, if any, additional records retention requirements should be established for the proposed Reliability Standards.

a. Improving Measures and Levels of Non-Compliance

i. Comments

241. A number of commenters raise concerns regarding the adequacy of current Measures and Levels of Non-Compliance. Some commenters, such as Nevada Companies, state that some Reliability Standards do not need multiple Measures and multiple Levels of Non-Compliance when such items do not fit the context of the specific Reliability Standard. According to Nevada Companies, some proposed Reliability Standards are more like business practices that are susceptible to a pass/fail test, and are not necessarily amenable to multiple Measures and Levels of Non-Compliance. Progress and Xcel maintain that Measures and Levels of Non-Compliance do not necessarily need to be added to every Reliability Standard.

242. Constellation is concerned that the Levels of Non-Compliance do not appear to be based on objective criteria, but rather appear to be based on arbitrary criteria and assumptions regarding the impact on reliability, which could lead to penalties that are excessive compared to the violation. MISO states that the original intent of the Levels of Non-Compliance was to assign a scale based on the impact on the Interconnection. MISO asserts that many Requirements are rated at too high a level and that many events that would be rated ''level 4'' are really just administrative requirements. It asserts that there are more ''level 4'' events than other categories, when logic would imply a pyramid structure with only a few items at the highest ''level 4.'' MISO states there should be a simplified process that measures the true impact on reliability. MISO and Dynegy state that there should also be an ''administrative infraction'' category created in addition to the current ''low,'' ''medium'' and ''high,'' so that the enforcement of supporting tasks can be handled expeditiously.

243. NYSRC states that, in NERC's rush to file with the Commission the 20 revised Reliability Standards with new Measures and Levels of Non-Compliance, the revised Reliability Standards were submitted to the NERC ballot body as a group, rather than individually. It maintains that the group treatment prevented stakeholders from providing the careful attention that each revised Reliability Standard deserves. NYSRC believes that, as a result, Requirements for a number of these Reliability Standards are flawed. While their prompt approval may be justified to have them in place for the upcoming summer, there is not a sufficient basis for the Commission to conclude that the weaknesses identified in these 20 Reliability Standards have been adequately addressed. NYSRC recommends that the Commission approve the 20 revised Reliability Standards and direct the ERO to more carefully address the weaknesses identified in those standards and to individually submit each revised standard to a ballot for separate consideration.

244. MISO, International Transmission and Constellation also raise concerns with NERC's Violation Risk Factors. They are concerned that risk is, in some cases, being confused with importance. For example, MISO states that NERC appears to be assigning risk to every sentence in each proposed Reliability Standard, including explanatory information and administrative requirements, thereby confusing risk with importance. MISO states that, while there may be many things that a transmission operator does that are important, failure to do an important thing one time would not necessarily jeopardize the Interconnection or cause a cascading failure.

245. MISO believes the definition of risk should reflect the likelihood that something serious is likely to happen if an event occurs. International Transmission, Constellation and MISO believe that a high risk event should, in and of itself, pose a significant threat to reliability and should not assume that multiple events occur simultaneously. According to MISO, only a small number of Requirements in the Reliability Standards fit the true definition of high risk. Constellation maintains that rating too many Requirements as high risk will water down the Requirements, and could shift the focus of attention away from the truly high risk Requirements, leading to a less effective, less efficient reliability program.

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225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[118] Although NERC does not formally define ''Measures,'' NERC explains that they ''are the evidence that must be presented to show compliance'' with a standard and ''are not intended to contain the quantitative metrics for determining satisfactory performance.'' NERC Comments to the Staff Preliminary Assessment at 104.

[119] ''Levels of Non-Compliance'' are established criteria for determining the severity of non-compliance with a Reliability Standard. The Levels of Non-Compliance range from Level 1 to Level 4, with Level 4 being the most severe.

[120] NOPR at P 105–07.

ii. Commission Determination

246. With regard to the comments of Nevada Companies, Progress and others, we believe that the ERO should have flexibility in initially developing appropriate Measures and Levels of Non-Compliance. For example, the ERO in the first instance should determine whether a Measure is necessary for every Requirement of a particular Reliability Standard, or whether every Reliability Standard must have the same number of Levels of Non-Compliance. Entities interested in developing meaningful Measures and Levels of Non-Compliance should, we find, participate in the ERO's Reliability Standards development process to ensure that their opinions are considered.

247. With regard to the concerns of MISO and Constellation, we agree as a general principle that Levels of Non-Compliance should be based on objective criteria and that a ''level 4'' violation should reflect a commensurate level of severity in its impact on Bulk-Power System reliability. However, we will allow the ERO in the first instance to determine whether specific revisions to particular Reliability Standards are needed to address these concerns. While we consider the appropriateness of Measures and Levels of Non-Compliance in our standard-by-standard review, we believe in the first instance it is the responsibility of the ERO to develop meaningful Measures and Levels of Non-Compliance, and those seeking to influence the process, as we have already found, should participate in the ERO's Reliability Standards development process. Likewise, we leave it to the ERO to determine initially whether there is any merit in developing a category of ''administrative infraction'' as suggested by some commenters.

248. The Commission agrees with NYSRC that, as a general matter, each Reliability Standard should be independently balloted in the Reliability Standards development process. However, the Commission will not require the ERO to resubmit each of the 20 revised Reliability Standards to the Reliability Standards development process for separate consideration. We do not believe such an action is required by the statute and would otherwise unnecessarily delay implementation of the proposed Reliability Standards. However, we expect that the ERO's Reliability Standards development process will provide adequate opportunity for independent consideration by stakeholders of each standard under consideration in the future.

249. MISO, International Transmission and Constellation raise concerns with NERC's Violation Risk Factors. The NERC board approved the Violation Risk Factors for Version 0 Reliability Standards and submitted them to the Commission on February 23, 2007. The Commission is reviewing the Violation Risk Factors in a seprate proceeding in Docket No. RR07–9–000. Thus, these issues are not ripe for consideration in this Final Rule. MISO, International Transmission and Constellation may raise concerns they have with the Violation Risk Factors in that separate proceeding.

b. Enforcement Implications

i. Comments

250. Certain commenters, such as EEI, Northeast Utilities, APPA and TAPS, state that Reliability Standards that lack clear Measures or Levels of Non-Compliance should not be fully enforced because they are not just and reasonable and raise potential due process concerns. APPA states that this is equally true of Reliability Standards that lack Violation Risk Factors or Violation Severity Levels because there is not proper notice as to the amount or range of monetary penalties to be assessed for a particular violation. APPA recommends that the Commission approve Reliability Standards that lack Measures and Violation Severity Levels, but that, until the deficiencies are corrected, require NERC and Regional Entities to waive imposition of monetary penalties. APPA would, however, reserve the Commission's right to impose monetary sanctions where warranted and also require compliance with NERC and Regional Entity remedial action directives for these Reliability Standards.

251. WIRAB disagrees that Reliability Standards can be consistently enforced based solely on sufficiently clear and enforceable Requirements. According to WIRAB, Levels of Non-Compliance are needed to inform parties of the consequences of non-compliance. WIRAB is concerned that a complex penalty structure that requires Regional Entities to consider multiple subjective mitigating and aggravating factors will compound the problems of missing and ambiguous Measures and Levels of Non-Compliance. A simple penalty structure would reduce enforcement ambiguities, increase uniformity and promote greater clarity. FirstEnergy states that, without Measures and Levels of Non-Compliance, a Reliability Standard cannot meet the Commission's requirement that a Reliability Standard must have a ''clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard.'' [121]

252. Progress and Xcel state that the Commission should clarify that the Measures and Levels of Non-Compliance are included solely for guidance and that only violations of the Requirements are subject to penalties. Portland General maintains that the Measures are an integral part of each Reliability Standard because entities will need to know the Measures so that they can build them into their compliance efforts from the beginning. In a similar vein, National Grid states that the lack of clear Measures or Levels of Non-Compliance also makes it difficult for users, owners and operators to tailor their businesses and practices toward compliance or to track ongoing compliance.

ii. Commission Determination

253. The Commission disagrees with commenters that a Reliability Standard cannot reasonably be enforced, or is otherwise not just and reasonable, solely because it does not include Measures and Levels of Non-Compliance. The Commission adopts the position it took in the NOPR that, while Measures and Levels of Non-Compliance provide useful guidance to the industry, compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts and circumstances of its use, ownership or operation of the Bulk-Power System. As we explained in the NOPR, and reiterate here:

> The most critical element of a Reliability Standard is the Requirements. As NERC explains, ''the Requirements within a standard define what an entity must do to be compliant * * * [and] binds an entity to certain obligations of performance under section 215 of the FPA.'' If properly drafted, a Reliability Standard may be enforced in the absence of specified Measures or Levels of Non-Compliance.[122]

254. APPA, WIRAB and others contend that, without Measures and Levels of Non-Compliance, a Reliability Standard should not be enforced. We disagree. Where a Reliability Standard has Requirements that are sufficiently clear so that an entity is aware of what it must do to comply, sufficient notice has been provided. While it can be helpful to provide additional guidance

[121] FirstEnergy at 10–11, citing NOPR at P 16; *see also* Order No. 672 at P 262, 321–37.

[122] NOPR at P 105 (footnote omitted).

regarding the amount or range of monetary penalties that may be assessed for a particular violation, the absence of such information is not a defect that renders a Reliability Standard unenforceable. Where the Requirement in a Reliability Standard is sufficiently clear, an entity will know what it should be doing to comply and will know that there are consequences for failure to comply. Therefore, where a Requirement in a Reliability Standard is sufficiently clear, we approve the Reliability Standard even though it may lack Measures or Levels of Non-Compliance. Where a Reliability Standard can be improved by providing missing Measures or Levels of Non-Compliance or by clarifying ambiguities with respect to Measures or Levels of Non-Compliance, we approve the Reliability Standard and concurrently direct NERC to modify it accordingly.[123]

255. In response to FirstEnergy, where the Requirement in a Reliability Standard is sufficiently clear, that Reliability Standard meets the requirement that it must have a ''clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard.'' The fact that NERC, in certain circumstances, did not include Measures and Levels of Non-Compliance does not make an otherwise clear Requirement unenforceable. Neither section 215 nor the Commission's regulations require the level of specificity sought by FirstEnergy in order for a Reliability Standard to be enforceable.

256. Progress and Xcel seek clarification that Measures and Levels of Non-Compliance are included solely for guidance and that only violations of the Requirements are subject to penalties. While the Commission generally agrees that it is a violation of the Requirements that is subject to a penalty, we recognize that because Measures are intended to gauge or document compliance, failure to meet a Measure is almost always going to result in a violation of a Requirement.

257. While we applaud NERC for adding additional levels of detail to its compliance enforcement program, we note that NERC and the Regional Entities should have further guidance as to how to use their enforcement discretion from the Commission's *Policy Statement on Enforcement*.[124] Further, if NERC does not submit Violation Risk Factors and Violation Severity Levels before NERC's enforcement program becomes effective, the Commission has reserved the ability to take appropriate action to ensure that the penalty-setting process described in the Sanction Guidelines is operative.[125]

c. Data Retention

i. Comments

258. In the NOPR, the Commission solicited comments regarding the sufficiency of data retention requirements in the Reliability Standards.[126] NERC states that the compliance data retention requirement is a defined element in the Reliability Standard template and that all data retention requirements, even those that are currently missing, will be reviewed and updated as part of the Reliability Standards Work Plan. NERC requests that the Commission not attempt to fix specific data retention requirements on the basis of comments received during this proceeding. NERC would prefer that the Commission direct those comments and any goals the Commission may have with regard to data retention back to NERC for resolution through the Reliability Standards development process.

259. SoCal Edison supports the data retention requirements in the Reliability Standards. APPA and SERC recommend that data retention requirements should be stated in each Reliability Standard and determined on a case-by-case basis through the Reliability Standards development process.

260. SERC agrees with NERC that an appropriate retention period is five years unless otherwise specified in a Reliability Standard. ISO-NE submits that any data retention policy established by the ERO should be in line with the five year civil penalty statute of limitations for violations of NERC Standards, while APPA cautions that detailed operational data may be so voluminous that a five-year retention requirement would be burdensome and of questionable value. MRO believes that the Reliability Standards retention period should be commensurate with operating and planning horizons, documentation related to a planning standard should be retained longer and that there should be a retention period of at least three years.

261. FirstEnergy states that individual record retention requirements on a standard-by-standard basis will create confusion and will be difficult to track. It therefore suggests that the Commission establish a uniform records retention standard of ''current calendar year plus three years'' for all proposed Reliability Standards that include a data retention requirement. Similarly, Entergy states that data retention requirements established for the Reliability Standards should be uniform and asks the Commission to direct the ERO to implement records retention requirements of no longer than three years.

262. International Transmission and Entergy comment that only the relevant core reliability requirements of the Reliability Standards should be subject to data retention requirements. International Transmission states that, in instances where retaining evidence of compliance is impractical or where no evidence exists of compliance, it is appropriate that no documentation be retained. Otherwise the record retention period should be no less than the prevailing audit frequency. Progress and Xcel agree that inclusion of data retention metrics in the Reliability Standards would be useful, but the Commission should make clear that violations of the data retention metrics are not subject to separate penalties under section 215 of the FPA.

ii. Commission Determination

263. The Commission agrees that it is appropriate for each Reliability Standard to have a data retention requirement. We are not persuaded that a one-size fits all approach to data retention is appropriate, however, because different Reliability Standards may require data to be retained for shorter or longer periods. Nor are we persuaded that the Commission should set a data retention requirement for any Reliability Standard for which one is currently lacking. Therefore, the Commission will not prescribe a set data retention period to apply to all Reliability Standards. Instead, the Commission directs the ERO to review and update the data retention requirements in each Reliability Standard as it is reevaluated through its Reliability Standards development process and submit the result for Commission approval. In doing so, NERC should take into account the comments raised in this proceeding and should seek input from other industry stakeholders.

[123] APPA raises concerns regarding the completeness or adequacy of Measures and Levels of Non-Compliance in its discussion of specific Reliability Standards. In such instances, APPA argues that the Reliability Standard should not be enforced until current Measures and Levels of Non-Compliance are improved or, where incomplete, new ones developed. Applying our above rationale to these particular circumstances, while the ERO should improve or develop Measures and Levels of Non-Compliance where necessary, we will not delay the enforcement of such Reliability Standards until the ERO develops such improvements or additions.

[124] *Enforcement of Statutes, Orders, Rules, and Regulations*, 113 FERC ¶ 61,068 (2005) (Policy Statement on Enforcement).

[125] *January 2007 Compliance Order* at P 93.

[126] NOPR at P 107.

3. Ambiguities and Potential Multiple Interpretations

264. In the NOPR, the Commission proposed that a proposed Reliability Standard that has Requirements that are so ambiguous as to not be enforceable should be remanded.[127] A Reliability Standard that has sufficiently clear Requirements, Measures and Levels of Non-Compliance language and otherwise satisfies the statutory standard of review should be approved. A proposed Reliability Standard that has sufficiently clear Requirements, but Measures or Levels of Non-Compliance that are ambiguous (or none at all), should be approved in some cases with a directive that the ERO develop clear and objective Measures and Levels of Non-Compliance language. In other cases, where some ambiguity may exist but there is also a common interpretation for certain terms based on the best practices within the industry, the Commission proposed to adopt that interpretation in the NOPR.

a. Comments

265. NERC maintains that, even if the Commission believes that there is some degree of ambiguity in some of the Reliability Standards, making the Reliability Standards mandatory enables NERC and Regional Entities to respond to questionable performance by clarifying to the responsible entity, and others, on a going-forward basis what behavior would constitute compliance with the Reliability Standards. Thereafter, participants would know how NERC and the Regional Entities were interpreting the Reliability Standards. According to NERC, this information would become part of the public record and help to eliminate any ambiguity as to what constitutes compliant and noncompliant behavior under a Reliability Standard. In contrast, if the Reliability Standards remain voluntary or temporarily unapproved, NERC contends that it and the Regional Entities will lack a legal basis to compel corrective behavior.

266. In contrast, Reliant urges the Commission to either not approve ambiguous Reliability Standards or approve them without subjecting entities to penalties. The level of ambiguity in many cases appears to violate the ''just and reasonable'' criteria for approval. It states that entities should not be found in violation based on retroactive interpretation of a Reliability Standard.

267. EEI expresses concern that approval and enforcement of a Reliability Standard that includes ambiguous requirements or lacks certain technical features or specificity may raise due process concerns if the required performance or performance measurements are not ''clear and unambiguous.'' Both in this docket and on a going forward basis, EEI questions whether proposed Reliability Standards with various shortcomings or deficiencies are sufficiently clear to meet the legal standard of review.

268. EEI and Wisconsin Electric state that it is not clear what ''common interpretations'' the Commission refers to in the NOPR or whether they are accepted or known across the industry. Wisconsin Electric states that common interpretations and best practices must be clearly spelled out and made available for review. These interpretations should be incorporated into the audit guidelines. Further, EEI states that common interpretations should not supersede provisions that are clearly stated in a Reliability Standard. According to EEI, if part of a proposed Reliability Standard is not clear, the NERC Reliability Standards development process should be used to clarify it. Further, EEI maintains that the Commission should require the ERO to review all existing industry sources, such as the NERC glossary or Institute of Electrical and Electronics Engineers (IEEE) standards, to supplement the interpretation of Reliability Standards. Undocumented ''common interpretations'' should be relied on only as a last resort. Moreover, EEI contends that, if such interpretations are to be used as a basis for assessing compliance and enforcement, they must be clearly spelled out and made available in advance.

269. MISO notes that some Reliability Standards may have portions applicable to five or more entities and that there are situations where a particular functional entity is not mentioned in the ''Applicability'' section of the Reliability Standard, but they show up in the Requirements. It believes that the industry needs a database-style tool that is a companion to the Reliability Standards that permits any functional entity to sort and find all requirements and supporting compliance information applicable to it. Such a tool would help entities prevent oversights and also help NERC eliminate redundancy in the Reliability Standards.

270. MISO also states that, in developing the Version 0 Reliability Standards, there was a conscious decision to include supporting information in the Reliability Standards themselves. As a result, there is now explanatory material in the Reliability Standards that is presented in context as Requirements. According to MISO, users now are trying to figure out how to measure Requirements that are really supporting text. MISO believes that the process should be simplified by separating each Reliability Standard into its core requirements and supporting information.

271. Similarly, Constellation, International Transmission and Dynegy comment that the Commission should distinguish between those Requirements in each Reliability Standard that are core requirements as opposed to supporting information, an explanatory statement, or an administrative process. International Transmission and Dynegy state that Measures should only apply to these core reliability requirements. Reliant is also concerned that each Reliability Standard contains a great deal of explanatory text, formatted to appear as enforceable obligations.

272. International Transmission, Reliant and MISO note that the proposed Reliability Standards contain many inherently ambiguous phrases or terms that can be misapplied, including ''adequate'' or ''adequately,'' ''sufficient,'' ''immediate,'' ''where technically feasible,'' ''as soon as possible'' and ''where practical.'' Reliant states that all ambiguous language must be eliminated before penalties can be assessed. MISO and Wisconsin Electric state that, while use of such terms may be acceptable in explanatory information, if a term cannot be definitively and objectively defined, it should not appear in the core Requirements of a Reliability Standard.

273. Alcoa reiterates its concern that the Commission has not defined the target level of reliability of the Bulk-Power System that the Reliability Standards are intended to achieve. Further, Alcoa is concerned that the proposed Reliability Standards are fragmented and overlap and in some cases may result in inconsistent treatment of the same issue. Alcoa states that the ERO should move towards a more encompassing approach for developing Reliability Standards in which a reliability goal is addressed from all aspects in a more consistent manner. Therefore, Alcoa maintains that the Commission should require NERC to engage in advance planning, mapping out what kind of reliability is adequate for the Bulk-Power System and then developing a plan to get there.

b. Commission Determination

274. The Commission finds that it is essential that the Requirements for each Reliability Standard, in particular, are sufficiently clear and not subject to

[127] NOPR at P 110–12.

multiple interpretations. Where the Requirements portion of a Reliability Standard is sufficiently clear (and no other issues have been identified), we approve the Reliability Standard. Upon review of the Reliability Standards and the comments submitted in response to the NOPR, the Commission finds that none of the Reliability Standards that we approve today contain an ambiguity that renders it unenforceable or otherwise unjust and unreasonable. As discussed in our standard-by-standard review, each Reliability Standard that we approve contains Requirements that are sufficiently clear as to be enforceable and do not create due process concerns.

275. The underlying assumption of many of the commenters seems to be that the Reliability Standards must spell out in minute detail all factual scenarios that might violate a Requirement and the precise consequences of that violation. But due process requirements do not go so far. Indeed, many government regulatory schemes provide far less specificity in terms of what is required or proscribed, and yet those regulations are routinely enforced.[128] Indeed, many tariffs on file with the Commission do not specify every compliance detail, but rather provide some level of discretion as necessary to carry out a particular act. This does not mean the tariffs are unenforceable; rather, it means that, if a dispute arises over compliance and there is a legitimate ambiguity regarding a particular fact or circumstance, that ambiguity can be taken into account in the exercise of the Commission's enforcement discretion. Therefore, we find that the Reliability Standards must strike a balance between a level of specificity that places users, owners and operators on notice of what is required, and a level of generality that encompasses unanticipated but serious actions or omissions that could affect Bulk-Power System reliability. We are satisfied that the Requirements portions of each Reliability Standard that we approve in this Final Rule appropriately strike this balance.

276. Some commenters argue that certain Reliability Standards require additional specificity or else users, owners and operators will not understand the consequences of a violation. This notion is similarly misplaced because the potential (if not actual) consequences for any violation are clearly spelled out—the statute permits the ERO to assess civil penalties of up to ''$1 million per violation, per day'' in addition to other remedies. The Commission has explained how it will approach civil penalties in its *Enforcement Policy Statement.* The ERO has provided guidance in its compliance filings, and will continue to do so, as to how it will administer compliance and enforcement functions. Clarity should not be confused with certainty. The former is provided by the statute, the Final Rule and the aforementioned authorities. The latter is simply unavailable in this context. Indeed, guaranteeing in advance specific enforcement outcomes hampers necessary and appropriate enforcement flexibility and poses the danger of users, owners and operators of the Bulk-Power System simply calculating the cost of a violation into the cost of doing business—a dynamic that would frustrate the very purpose of a mandatory Reliability Standards system, which is to promote reliability.

277. The Commission agrees with NERC that, even if some clarification of a particular Reliability Standard would be desirable at the outset, making it mandatory allows the ERO and the Regional Entities to provide that clarification on a going-forward basis while still requiring compliance with Reliability Standards that have an important reliability goal. Further, we support the ERO's efforts to review each of the current Reliability Standards to improve them and provide yet further clarity. We encourage all interested entities, especially those that have identified specific suggestions for improvement, to participate in the ERO's Reliability Standards development process.

278. The Commission finds that these Reliability Standards, with the interpretations provided by the Commission in the standard-by-standard discussion, meet the statutory criteria for approval as written and should be approved. In any event, penalties are warranted under section 215 only when an entity knew or reasonably should have known that its acts or omissions were contrary to the Reliability Standards. Wisconsin Electric seems to interpret the Commission as requiring that users, owners and operators of the Bulk-Power System comply with best practices under the Reliability Standards. We disagree. While we appreciate that many entities may perform at a higher level than that required by the Reliability Standards, and commend them for doing so, the Commission is focused on what is required under the Reliability Standards; we do not require that they exceed the Reliability Standards. We agree with EEI that a common interpretation cannot supplant a provision that is clearly stated in a Reliability Standard. We also agree, however, that, over time, these interpretations could be incorporated either into the Reliability Standard itself through the Reliability Standards development process or the ERO and Regional Entity audit guidelines.

279. The Commission disagrees with MISO that some Reliability Standards as proposed are unclear with respect to applicability. In certain situations, Bulk-Power System reliability depends on more than one entity complying with a Reliability Standard. Further, in certain situations, the Requirement of a Reliability Standard may reference an entity that is not itself responsible for compliance with the Reliability Standard, for example, where an entity responsible for compliance must report information to or communicate with another entity, without that other entity being required to comply with the Reliability Standard. However, in its review of Reliability Standards, the ERO should ensure that, if a functional entity must comply with the Reliability Standards, it must be mentioned in the Applicability section. In this regard, we encourage the ERO to consider development of a database-style tool that is a companion to the Reliability Standards that permits any user, owner or operator to sort and find all Requirements applicable to it.

280. In response to MISO, Constellation, International Transmission and Dynegy, the Commission believes that the Requirements in each Reliability Standard are core obligations and that the Measures and Levels of Non-Compliance provide useful guidance to the industry and can be supporting information, an explanatory statement or an administrative process. As discussed above, NERC is to enforce the Requirements in a Reliability Standard. The Measures are part of the Reliability Standards and, if not met, are almost always going to result in a violation of a Requirement.

281. The Commission has previously addressed Alcoa's concerns about defining the target level of reliability of the Bulk-Power System that the Reliability Standards are intended to achieve. In the *January 2007 Compliance Order*, the Commission directed the ERO to establish a stakeholder process to define adequate level of reliability.[129] While the Commission agrees that this is a worthwhile effort, we disagree with

[128] Many sections of the FPA, including section 215, use such terms as just and reasonable or unduly discriminatory or preferential or even the public interest.

[129] *January 2007 Compliance Order* at P 16.

Alcoa that Reliability Standards cannot be approved until this analysis is done. Such analysis is not required by the statute, and Alcoa has not identified any compelling reason why the proposed Reliability Standards are defective without the benefit of such analysis.

4. Technical Adequacy

282. In the NOPR, we stated that we are cautious about drawing any general conclusions about technical adequacy as we consider this a matter that can only be addressed on a standard-by-standard basis. Where we have specific concerns regarding whether a Requirement set forth in a proposed Reliability Standard may not be sufficient to ensure an adequate level of reliability or represents a ''lowest common denominator'' approach, we address those concerns in the context of that particular Reliability Standard.[130]

a. Comments

283. NYSRC shares the Commission's concerns regarding the use of a ''lowest common denominator'' approach in the development of Reliability Standards and agrees that this concern can be addressed only on a standard-by-standard basis. NYSRC maintains that, in commenting on pending ERO Reliability Standards, the NYSRC believed could weaken existing Reliability Standards, the NERC drafting team responded that a region is free to develop more stringent Reliability Standards. NYSRC maintains that the ability of a Regional Entity to propose more stringent Reliability Standards to meet the reliability needs of that region does not justify the weakening of continent-wide Reliability Standards by use of a ''lowest common denominator'' approach to achieve greater support for a proposed Reliability Standard. NYSRC recommends that the Commission reaffirm that it will carefully review subsequent proposed ERO Reliability Standards to ensure that they are technically adequate and do not weaken the current level of reliability.

284. ATC agrees with the Commission that the industry, organized in Regional Entities under the ERO, must continue to be wholly accountable for the technical adequacy of the Reliability Standards. ATC thus suggests that the Commission's efforts to ''independently assess the technical adequacy of any proposed Reliability Standard'' focus on Commission participation in and support of the Reliability Standards development processes at NERC and at the regions.

[130] NOPR at P 115.

b. Commission Determination

285. The Commission fully intends to address technical adequacy on a standard-by-standard basis and the Commission agrees that the ability of a Regional Entity to propose more stringent Reliability Standards to meet the reliability needs of that region does not justify the weakening of continent-wide Reliability Standards. In this regard, we note that, in the *January 2007 Compliance Order*, we directed the ERO to closely monitor the voting results for Reliability Standards and to report to us quarterly for the next three years its analysis of the voting results, including trends and patterns that may signal a need for improvement in the voting process, such as the rejection of a Reliability Standard and subsequent ballot approval of a less stringent version of the Reliability Standard.[131] The Commission will use this information to evaluate whether it needs to re-examine the Reliability Standard development procedure. In doing so, the Commission will also be sensitive to concerns that ''lowest common denominator'' Reliability Standards are being developed.

286. The Commission agrees that its staff should participate in and support the Reliability Standards development processes, to the extent consistent with its regulatory role. The Commission's participation in those processes will not constitute its entire assessment of the technical adequacy of a proposed Reliability Standard. The Commission will also conduct an assessment during its rulemaking or order process after the Reliability Standard is submitted by the ERO to the Commission for approval.

5. Fill-in-the-Blank Standards

287. The NOPR explained that certain Reliability Standards, referred to as fill-in-the-blank standards, require the regional reliability organizations to develop criteria for use by users, owners or operators within each region.[132] In the NOPR, the Commission expressed concern regarding the potential for the fill-in-the-blank standards to undermine uniformity. With regard to NERC's stated intention to submit an action plan and schedule for completing the fill-in-the-blank standards, the NOPR explained that NERC's plan must be consistent with the discussion in Order No. 672 regarding uniformity and the limited circumstances in which a regional difference would be permitted.[133]

[131] *January 2007 Compliance Order* at P 18.

[132] NOPR at P 116.

[133] *Id.* at P 121, citing Order No. 672 at P 292; *ERO Certification Order* at P 274.

288. Further, the NOPR proposed to require supplemental information regarding any Reliability Standard that requires a regional reliability organization to fill in missing criteria or procedures. The Commission explained that, ''where important information has not been provided to us to enable us to complete our review, we are not in a position to approve those Reliability Standards.'' [134] Therefore, the NOPR proposed to not approve or remand such Reliability Standards until all necessary information is provided, although compliance would still be expected as a matter of good utility practice.

a. Comments

289. NERC, APPA and TAPS support the Commission's proposal to defer consideration of fill-in-the-blank standards. APPA believes that the Commission's proposal balances the need for greater uniformity against the need for regional flexibility.

290. NERC agrees with the Commission's proposal to hold 24 Reliability Standards (mainly fill-in-the-blank standards) as pending at the Commission until further information is provided, and to require that Bulk-Power System users, owners and operators follow these pending standards as ''good utility practice'' pending their approval by the Commission. NERC also agrees that it and the Regional Entities can monitor compliance with these pending standards using the ERO's authority pursuant to § 39.2(d) of the Commission's regulations. NERC believes this approach is necessary to ensure that there will be no gap during the transition from the current voluntary reliability regime to mandatory and enforceable Reliability Standards.

291. While TAPS supports deferring consideration of fill-in-the-blank standards, it urges the Commission to view with skepticism regional differences within an Interconnection that are not justified by physical differences. It states that such regional Reliability Standards, even if more stringent, can wreak havoc on competitive markets, especially where entities within the same transmission system or RTO footprint are subject to different regional Reliability Standards. For example, TAPS maintains that inconsistent regional underfrequency load shedding (UFLS) Reliability Standards not justified by physical differences impose unjust burdens on joint action agencies whose integrated load is split between NERC regions. Further, according to TAPS, a region's

[134] NOPR at P 123.

choice may reflect the historical lack of a balanced process for developing Reliability Standards at the regional level, allowing certain classes of market participants to determine the region's choice.

292. According to ISO–NE, if the Commission withholds approval of these 24 Reliability Standards, the Commission should also withhold approval of Reliability Standards that rely, by reference, on such fill-in-the-blank Reliability Standards.[135] ISO–NE submits that, until the missing information has been provided in the cross-referenced fill-in-the-blank Reliability Standard, it will be impossible for the applicable entities to determine exactly what criteria they are expected to satisfy. APPA raises similar concerns, and suggests that the Commission approve such Reliability Standards but not enforce them until the cross-referenced fill-in-the-blank Reliability Standards are approved.

293. MISO and Wisconsin Electric believe that the fill-in-the-blank standards may be acceptable in certain situations. They give regions some flexibility in implementation, and allow the deployment of a Reliability Standard where it would be difficult to get consensus across several regions. They also move the reliability agenda forward on issues that are historically under state jurisdiction, and some are an accommodation to those regions that want to have a higher Reliability Standard.

294. EEI agrees with the NOPR that, regarding Reliability Standards for which the Commission needs additional information, compliance in the interim would be expected as a matter of good utility practice. While EEI agrees with this approach, it also cautions that the good utility practice provision of an OATT should not be used as an alternative means of enforcement outside of section 215 of the FPA. Similarly, FirstEnergy posits that good utility practice is subject to interpretation and by itself does not provide the level of guidance needed for a mandatory and enforceable Reliability Standard. It asserts that the Commission should not impose compliance burdens indirectly where it has not imposed them directly. Xcel asserts that the Commission should rescind the *Reliability Policy Statement* that defines good utility practice under the *pro forma* OATT, effective when the Reliability Standards become mandatory in June 2007, because a reliability-related violation should not be subject to two separate enforcement schemes.

295. NPCC recommends that any of the 24 fill-in-the-blank standards that are required to be Reliability Standards should be developed as regional Reliability Standards by the Regional Entity for compliance monitoring and enforcement, backed by the Commission and Canadian provincial regulatory and/or governmental authorities.

296. California PUC states that the NOPR seeks national uniformity notwithstanding regional differences. It states that, in the Western Interconnection, there are 15 existing, enforceable WECC standards pursuant to the WECC Reliability Management System (RMS) that overlap the proposed mandatory Reliability Standards. Five of these WECC standards fall into the fill-in-the-blank standards category. However, there are three additional WECC RMS standards already in effect in the Western Interconnection that do not have a corresponding proposed Reliability Standard. California PUC asks that the Commission consider approving these additional three standards for enforcement in the Western Interconnection. California PUC states that there is no reason for the Commission to exclude any WECC standard already in effect, and that ignoring these established standards when the Reliability Standards are scheduled to go into effect can threaten reliability already being achieved in the Western Interconnection.

b. Commission Determination

297. The Commission requires supplemental information for any Reliability Standard that currently requires a regional reliability organization to fill in missing criteria or procedures. Where important information has not yet been provided to us to enable us to complete our review, we are not in a position to approve or remand those Reliability Standards.[136] Accordingly, we will not approve or remand such Reliability Standards until the ERO submits further information. Until such information is provided, compliance with fill-in-the-blank standards should continue on a voluntary basis, and the Commission considers compliance with such Reliability Standards to be a matter of good utility practice.

298. As noted above, some commenters such as TAPS urge the Commission to view most regional differences with skepticism, while others such as MISO and Wisconsin Electric favor some regional variation. The Commission affirms the approach that it articulated in the NOPR.[137] We share commenters' concerns regarding the potential for fill-in-the-blank standards to undermine uniformity. While uniformity is the goal with respect to Reliability Standards, we recognize that it may not be achievable overnight. Over time, we would expect that the regional differences will decline and uniform and best practices will develop. In Order No. 672, the Commission identified two instances where regional differences may be permitted, *i.e.*, regional differences that are more stringent than continent-wide Reliability Standards (including those that address matters not addressed by a continent-wide Reliability Standard) and a regional difference necessitated by a physical difference in the Bulk-Power System.

299. The ERO should develop the needed information for the Commission to act on the fill-in-the-blank standards consistent with these criteria. If a regional difference is warranted, a regional fill-in-the-blank proposal must be developed through an approved regional Reliability Standards development process, and submitted to the ERO. If approved by the ERO, the ERO will then submit it to the Commission for approval.

300. The Commission disagrees with ISO–NE, ISO/RTO Council and APPA that 16 additional Reliability Standards should not be acted on or enforced at this time. The fact that a Reliability Standard simply references another, pending Reliability Standard, one that is not being approved or remanded here, does not alone justify not approving the former Reliability Standard. Rather, such a reference may be considered in an enforcement action, if relevant, but is not a reason to delay approval of enforcement of the Reliability Standard. We find that the Reliability Standards that reference a pending Reliability Standard contain the appropriate level of specificity necessary to provide notice to users, owners and operators of the Bulk-Power System as to what is required.

301. The Commission has reviewed the 16 Reliability Standards identified by commenters as referencing a Reliability Standard that the Commission proposed not to approve or remand. It appears that many of these Reliability Standards either refer to the process of collecting data or reference Requirements that entities are generally

[135] ISO–NE and ISO/RTO Council state that the following Reliability Standards are dependent upon ''fill-in-the-blank'' standards: FAC–013–1, MOD–010–0, MOD–012–0, MOD–016–1, MOD–017–0, MOD–018–0, MOD–019–0, MOD–021–0, PRC–004–1, PRC–007–0, PRC–008–0, PRC–009–0, PRC–015–0, PRC–016–0, PRC–018–1 and PRC–021–0.

[136] NOPR at P 123.

[137] *Id.* at P 121 (footnote omitted).

aware of because they have already been following these Reliability Standards on a voluntary basis. For example, MOD–012–0 requires transmission and generator owners to provide data to the regional reliability organization to support system modeling required by MOD–013–0. The NOPR proposed not to approve or remand MOD–013–0 partly because MOD–013–0 requires development of dynamics data requirements and reporting procedures that have not been submitted for our review. In addition, we proposed not to act on MOD–013–0 partly because it applies to a regional reliability organization and the Commission was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced by NERC. That is not the case with MOD–012–0, which applies to entities that are clearly users, owners and operators of the Bulk-Power System. Although MOD–012–0 references MOD–013–0, its applicability to a subset of users, owners and operators is not at issue. Accordingly, the Commission denies the requests to leave pending this and similar data-related Reliability Standards and reaffirms the NOPR approach described above.

302. While EEI and others agree with the proposal that, in the interim, compliance with Reliability Standards for which the Commission needs additional information should continue as a matter of good utility practice, they caution that this should not lead to an alternative means of enforcement outside of section 215 of the FPA. In our *Reliability Policy Statement*, we explained that compliance with NERC Reliability Standards (or more stringent regional standards) is expected as a matter of good utility practice as that term is used in the *pro forma* OATT.[138] The Commission continues to expect compliance with such Reliability Standards as a matter of good utility practice. That being said, the Commission agrees that retaining a dual mechanism to enforce Reliability Standards both as good utility practice and under section 215 of the FPA is inappropriate; the OATT only applies to entities subject to our jurisdiction as public utilities under the FPA, while section 215 defines more broadly our jurisdiction with respect to mandatory Reliability Standards. We therefore do not intend to enforce, as an OATT violation, compliance with any Reliability Standard that has not been approved by the Commission under section 215.

303. With regard to California PUC's comments, we recognize the desire to retain certain existing regional standards that apply to the Western Interconnection, which are currently enforceable pursuant to WECC's RMS program. However, these regional Reliability Standards have not been submitted to the Commission by the ERO pursuant to the process set forth in Order No. 672. Accordingly, California PUC's concerns are beyond the scope of this proceeding. The Commission will review the WECC standards once they are approved by the ERO and submitted to the Commission for approval.

F. Discussion of Each Individual Reliability Standard

304. The NOPR reviewed each proposed Reliability Standard and provided an analysis by chapter according to the categories of Reliability Standards defined in NERC's petition. Each chapter began with an introduction to the category, followed by a discussion of each proposed Reliability Standard. The Final Rule takes a similar approach.

1. BAL: Resource and Demand Balancing

305. The six Balancing (BAL) Reliability Standards address balancing resources and demand to maintain interconnection frequency within prescribed limits.

a. Real Power Balancing Control Performance (BAL–001–0)

306. The purpose of this Reliability Standard is to maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time. The proposed Reliability Standard would apply to balancing authorities. In the NOPR, the Commission proposed to approve BAL–001–0 as mandatory and enforceable.[139]

i. Comments

307. APPA agrees with the Commission that BAL–001–0 is sufficient for approval as a mandatory Reliability Standard.

ii. Commission Determination

308. For the reasons stated in the NOPR, the Commission approves BAL–001–0 as mandatory and enforceable.

b. Regional Difference to BAL–001–0: ERCOT Control Performance Standard 2

309. NERC approved a regional difference for ERCOT by allowing it to be exempt from Requirement R2 in BAL–001–0, which requires that the average area control error (ACE) for each of the six ten-minute periods during the hour must be within specific limits, and that a balancing authority achieve 90 percent compliance. This Requirement is referred to as Control Performance Standard 2 (CPS2).

310. NERC explains that ERCOT requested a waiver of CPS2 because: (1) ERCOT, as a single control area[140] asynchronously connected to the Eastern Interconnection, cannot create inadvertent flows or time errors in other control areas and (2) CPS2 may not be feasible under ERCOT's competitive balancing energy market. In support of this argument, ERCOT cites to a study that it performed showing that under the new market structure, the ten control areas in its region individually were able to meet CPS2 standards while the aggregate performance of the ten control areas was not in compliance. Since requesting the waiver from CPS2, ERCOT has adopted section 5 of the ERCOT protocols which identify the necessary frequency controls needed for reliable operation in ERCOT.

311. In the NOPR, the Commission proposed to approve the ERCOT regional difference and have the ERO submit a modification of the ERCOT regional difference to include the requirements concerning frequency response contained in section five of the ERCOT protocols.[141]

i. Comments

312. No comments were filed on this regional difference.

ii. Commission Determination

313. The Commission approves the ERCOT regional difference as mandatory and enforceable. Order No. 672 explains that ''uniformity of Reliability Standards should be the goal and the practice, the rule rather than the exception.'' [142] However, the Commission has stated that, as a general matter, regional differences are permissible if they are either more stringent than the continent-wide Reliability Standard, or if they are necessitated by a physical difference in the Bulk-Power System.[143] Regional differences must still be just, reasonable, not unduly discriminatory or

[138] *Policy Statement on Matters Related to Bulk Power System Reliability*, 107 FERC ¶ 61,052 at P 23–26 (2004) (*Reliability Policy Statement*).

[139] NOPR at P 136.

[140] At the time NERC granted this regional difference, the term ''control area'' was used instead of ''balancing authority.'' For purposes of this discussion, they are the same.

[141] *Id.* at P 143.

[142] Order No. 672 at P 290.

[143] *Id.* at P 291.

preferential and in the public interest.[144]

314. The Commission finds that ERCOT's approach under section 5 of the ERCOT protocols appears to be a more stringent practice than Requirement R2 in BAL–001–0 and therefore approves the regional difference.

315. As proposed in the NOPR, the Commission directs the ERO to file a modification of the ERCOT regional difference to include the requirements concerning frequency response contained in section 5 of the ERCOT protocols. As with other new regional differences, the Commission expects that the ERCOT regional difference will include Requirements, Measures and Levels of Non-Compliance sections.

c. Disturbance Control Performance (BAL–002–0)

316. The stated purpose of this Reliability Standard is to use contingency reserves to balance resources and demand to return Interconnection frequency to within defined limits following a reportable disturbance. The proposed Reliability Standard would apply to balancing authorities, reserve sharing groups [145] and regional reliability organizations.

317. In the NOPR, the Commission proposed to approve Reliability Standard BAL–002–0 as mandatory and enforceable.[146] In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to BAL–002–0 that: (1) Includes a Requirement that explicitly allows demand-side management (DSM) to be used as a resource for contingency reserves; (2) develops a continent-wide contingency reserve policy; [147] (3) includes a Requirement that measures response for any event or contingency that causes a frequency deviation; [148] (4) substitutes the ERO for the regional reliability organization as the compliance monitor and (5) refers to the ERO rather than the NERC Operating Committee in Requirements R4.2 and R6.2.

i. General Comments

318. Constellation supports the Commission's proposals with respect to BAL–002–0.

319. Xcel notes that this Reliability Standard would apply to a reserve sharing group, which is not defined in the NERC Functional Model but generally consists of a group of separate entities. Xcel states it is not clear how compliance and penalties would be applied to a reserve sharing group and seeks clarification from the Commission. As a second concern, Xcel states it is not clear who calculates ACE between a balancing authority and a reserve sharing group and states that the Commission should require the ERO to clarify this issue when modifying the Reliability Standard.

ii. Commission Determination

320. The Commission approves BAL–002–0. With regard to Xcel's concern, the NERC glossary defines a reserve sharing group as ''two or more balancing authorities that collectively maintain, allocate, and supply operating reserves required for each balancing authority's use in recovering from contingencies within the group.'' [149] The Commission notes that the Reliability Standard's Requirements and Levels of Non-Compliance are applicable to both balancing authorities and reserve sharing groups and are clear as to the roles and responsibilities of these entities. The ERO will be responsible for ensuring compliance with this Reliability Standard for all applicable entities. A reserve sharing group, however, as an independent organization, is able to determine on its own as a commercial matter whether any penalties related to non-compliance should be re-apportioned among the members of the group. With regard to Xcel's concern about which entity calculates ACE, it is not clear from Xcel's comments what it believes needs clarification. In general, we understand that all balancing authorities are required to calculate ACE with the exception of balancing authorities that use dynamic schedules to provide all regulating reserves from another balancing authority. As such, reserve sharing groups will not calculate ACE; they will rely on balancing authorities to do so.

321. The Commission adopts the NOPR's proposal to require the ERO to develop a modification to the Reliability Standard that refers to the ERO rather than to the NERC Operating Committee in Requirements R4.2 and R6.2. The ERO has the responsibility to assure the reliability of the Bulk-Power System and should be the entity that modifies the Disturbance Recovery Period as necessary. As identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance monitor.[150] The remaining modifications to this Reliability Standard proposed in the NOPR are discussed below.

iii. Including Demand-Side Management as a Resource

(a) Comments

322. SMA supports the Commission's proposed requirement explicitly allowing demand-side response as a resource and agrees with the Commission that DSM and direct load control should be considered on the same basis as conventional generation or any other technology with respect to contingency reserves. SMA states that nationwide its members provide over 1,300 MW of demand that is curtailable on 10 minutes notice or less and indicates that most of this curtailable capacity is committed to utilities pursuant to retail tariffs or contracts for operating reserves.

323. FirstEnergy states that demand-side resources should be included as another tool for the balancing authority to use in meeting the control performance and disturbance control standards. According to FirstEnergy, demand-side resources should mimic the requirements of generation resources but with a decrease in load rather than an increase in generation response.

324. Process Electricity Committee generally supports the proposal to treat demand response resources in a manner similar to conventional generation so long as such demand resources participate in such DSM programs voluntarily and comply with all applicable Reliability Standards and requirements. Process Electricity Committee recommends that the Commission modify its proposal to clarify that any such demand response resources may be used only with the end-user's express written agreement pursuant to clear contractual rights and obligations.

325. NY Major Consumers states that many large end use customers currently have the ability to provide all ancillary

[144] *Id.*

[145] A ''reserve sharing group'' is a group of two or more balancing authorities that collectively maintain, allocate and supply operating reserves. See NERC Glossary at 15.

[146] NOPR at P 151.

[147] The NOPR explained that this could be accomplished by modifying Requirement R2 or developing a new Reliability Standard.

[148] This proposed Requirement addressed modifications to Requirement R3.1 which are described in the ''Disturbance Control Standard and the Associated Reserve Requirement'' section of this Final Rule.

[149] NERC Glossary at 15.

[150] *See* Applicability Issues: Regional Reliability Organizations, *supra* section II.C.5. This directive applies generically to all Reliability Standards that identify the regional reliability organization as the compliance monitor.

services, or are capable of providing these services in the near future and that this capability has been recognized by Commission staff in Docket No. AD06–2–000, Assessment of Demand Response Resources. NY Major Consumers further states that there remains some ambiguity in the proposed Reliability Standards as to the eligibility of technically-qualified loads to provide these services and requests that the Commission eliminate any such uncertainty and amend the proposed Reliability Standards as further described in its comments.

326. Some commenters [151] disagree with the Commission's proposal to add a requirement explicitly allowing DSM as a resource for contingency reserves. NERC, APPA and ISO–NE state that this requirement is too prescriptive. NERC maintains that explicitly allowing DSM goes well beyond the bounds of current utility practice and suggests an improved directive would simply place DSM on the same basis as other resources. APPA states that DSM resources should be included as an option for a balancing authority to use in meeting its reserve obligations, but that the Commission should not require NERC to modify the Reliability Standard to explicitly identify DSM or any other type of capacity as a resource for meeting reserve contingencies.

327. In addition, ISO–NE states that DSM, to which it has access, responds to capacity requirements and may not provide relief on a contingency basis, but states that it has a limited number of resources that could meet this requirement. SDG&E argues that DSM participation in real-time is often unknown in comparison to conventional generation and further states that the NOPR does not explain how DSM could be used in real-time dispatch. Further, SDG&E maintains that the Commission has not established a clear and workable definition of DSM.

328. MISO states that it is not clear about the meaning and questions the value of the Commission's proposed requirement to include DSM as a contingency reserve resource.[152]

329. While EEI and MRO do not disagree with the Commission's proposed requirement to include DSM, EEI states that both generation and controllable load should comply with the same requirements to the maximum extent possible, while MRO suggests that this requirement should also include study and testing requirements.

(b) Commission Determination

330. We direct the ERO to submit a modification to BAL–002–0 that includes a Requirement that explicitly provides that DSM may be used as a resource for contingency reserves, subject to the clarifications provided below.

331. The Commission disagrees with APPA that we should not explicitly identify any type of capacity as a resource for meeting reserve contingencies. The Commission believes that listing the types of resources that can be used to meet contingency reserves makes the Reliability Standard clearer, provides users, owners and operators of the Bulk-Power System a set of options to meet contingency reserves, and treats DSM on a comparable basis with other resources.

332. Many commenters argue that the Commission's proposed directive that would explicitly allow DSM as a resource for contingency reserves is too prescriptive. Concerns in this area generally fall into three categories: (1) that DSM should be treated on a comparable basis as other resources; (2) that the Reliability Standard should be based on meeting an objective as opposed to stating how that objective is met and (3) that DSM may not be technically capable of providing this service.

333. With regard to the first concern, the Commission clarifies that the purpose of the proposed directive is to ensure comparable treatment of DSM with conventional generation or any other technology and to allow DSM to be considered as a resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option.[153] The proposed directive as written achieves that goal. With regard to the second concern, we believe that this Reliability Standard is objective-based and we reiterate that we are simply attempting to make it inclusive of other technologies that may be able to provide contingency reserves, and are not directing the use of any particular type of resource. By specifying DSM as a potential resource for contingency reserves, the Commission is clarifying the substance of the Reliability Standard.[154]

334. With regard to commenters' concern that DSM may not be technically possible, we first clarify that in order for DSM to participate, it must be technically capable of providing contingency reserve service. We expect that the ERO would determine what technical requirements DSM would need to meet to provide contingency reserves.[155] While ISO–NE, APPA and SDG&E suggest that there is limited access to qualified DSM or that DSM may not be optimal from a technical standpoint, we note that SMA's comments state that its members are currently providing over 1,300 MW of contingency reserve service through retail tariffs or contracts. Alcoa states that it could use the digital controls of its aluminum smelters to provide load control that would be superior to conventional generation in terms of ramp rate and speed of response. Also, the Commission notes that New Zealand is currently using DSM for contingency reserves.[156] Nonetheless, our requirement is that BAL–002–0 explicitly provides that demand resources may be used as a resource for contingency reserves without requiring the use of a specific resource or type of resource.

335. Accordingly, the Commission directs the ERO to explicitly allow DSM as a resource for contingency reserves, and clarifies that DSM should be treated on a comparable basis and must meet similar technical requirements as other resources providing this service.[157]

iv. Continent-Wide Contingency Reserve Policy

(a) Comments

336. The Commission proposed in the NOPR to direct the ERO to develop one uniform continent-wide contingency reserves policy. Specifically, the Commission noted that the appropriate mix of operating reserves, spinning reserves and non-spinning reserves should be addressed on a consistent basis and consideration should be given to the amount of frequency response from generation or load needed to assure reliability. The Commission proposed that this policy be neutral as to the source of the contingency reserves in terms of ownership or technology.

337. SMA supports the Commission's proposal to develop a continent-wide contingency reserve policy and agrees with the Commission that the policy should be neutral as to the source of the

[151] *See* NERC, ISO–NE, APPA and SDG&E.

[152] MISO–PJM comments jointly with respect to IRO–006–3 only.

[153] NOPR at P 157.

[154] Order No. 672 at P 260.

[155] *Id.* (''We leave it to the ERO to develop proposed Reliability Standards that appropriately balance reliability principles and implementation features.'')

[156] *See http://www.electricitycommission.govt.nz/pdfs/rulesandregs/rules/rulespdf/Part-C-sched-C5-1Dec06.pdf.*

[157] ERCOT presently uses ''Load Acting as a Resource'' as part of its reserves which are triggered at a specified frequency. This is similar to but not the same as generation and is an example of how load can perform as a resource.

contingency reserves in terms of ownership or technology. EEI and FirstEnergy both support development of a continent-wide contingency reserve policy but suggest the need for regional variations across the Bulk-Power System. For instance, FirstEnergy suggests that a one percent peak load spinning requirement in the Eastern Interconnection could be the equivalent of a two percent spinning requirement in the Western Interconnection.

338. Other commenters [158] disagree with the Commission's proposal to have NERC develop a continent-wide contingency reserve policy and instead support an Interconnection-wide or regional approach. APPA, LPPC and MISO state that a continent-wide policy would not work because of regional differences such as size, topology, mix of resources and likely contingencies. While APPA supports the Commission's proposal that contingency reserves should be based on the reliability risk of a balancing authority not meeting load, it favors an Interconnection-wide approach. MISO suggests that defining certain terms such as ''spinning,'' ''non-spinning,'' ''contingency'' and ''replacement'' and having common calculations would be of value. It contends, however, that EPAct does not apply to resource adequacy requirements, implying that the Commission therefore is prevented from directing the development of a continent-wide contingency reserve policy. International Transmission shares this view.

339. California PUC states that some customers can tolerate a limited number of outages and suggests that it may be more cost-effective to provide back-up power to customers with high reliability needs rather than designing the entire system to a very high and expensive level. California PUC disagrees with the Commission that contingency reserves should be based only on the reliability risk of a balancing authority not meeting load. It suggests that certain other relevant factors should be considered, such as the number of customers or MW lost, the value that customers in a certain area place on reliability and the costs of avoiding outages (the cost of reserves).

(b) Commission Determination

340. We direct the ERO to submit a modification to BAL–002–0 to include a continent-wide contingency reserve policy. We are not prescribing the details of that policy. As the Commission stated in the NOPR, ''[w]hile the Commission believes it is appropriate for balancing authorities to have different amounts of contingency reserves, these amounts should be based on one uniform continent-wide contingency reserves policy. The policy should be based on the reliability risk of not meeting load associated with a particular balancing authority's generation mix and topology.'' [159] In addition, the contingency reserves should include sufficient frequency responsive resources such that the net frequency response of the balancing authority is sufficient for either interconnected or isolated operation.[160]

341. The Commission agrees with MISO that certain terms such as ''spinning'' and ''non-spinning'' or any other term used to describe contingency or operating reserves could be developed continent-wide. Additionally, we believe the technical requirements for resources that provide contingency reserves should not change from region to region.

342. We believe a continent-wide contingency reserves policy would assure that there are adequate magnitude and frequency responsive contingency reserves in each balancing authority. This will improve performance so that no balancing authority will be doing less than its fair share.

343. With regard to California PUC's concerns regarding the cost of providing reserves, and the suggestion that loss of firm load may be an acceptable alternative to enhanced reliability of the system, the Commission disagrees. Loss of firm load should not be permitted in planning the system for a single contingency. However, the Commission recognizes the appropriate concern of California PUC regarding costs. The California PUC can have a strong role in this area by encouraging or requiring DSM programs that can reduce the demand on the transmission system.

344. With regard to statements that EPAct does not apply to resource adequacy, we note that this Reliability Standard does not concern resource adequacy, but addresses contingency reserves, which are operating and not planning reserves. Operating reserves are not the same as resource adequacy, a planning element. Section 215 authorizes the Commission to approve Reliability Standards for contingency reserves because they are necessary for real-time Reliable Operation of the Bulk-Power System.

345. Accordingly, the Commission requires the ERO to develop a continent-wide contingency reserve policy through the Reliability Standards development process, which should include uniform elements such as certain definitions and requirements as discussed in this section. The Commission clarifies that the continent-wide policy can allow for regional differences pursuant to Order No. 672, but that the policy should include procedures to determine the appropriate mix of operating reserves, spinning and non-spinning, as well as requirements pertaining to the specific amounts of operating reserves based on the load characteristics and magnitude, topology, and mix of resources available in the region.

v. Disturbance Control Standard and the Associated Reserve Requirement

(a) Comments

346. The Commission identified two items in the Disturbance Control Standard section of the NOPR. In the first item, the Commission agreed with the interpretation that the 15 minute limit on a reportable disturbance was ''absolute, objective, and measurable'' and therefore enforceable in the present Reliability Standard. The second item resulted in a proposal to modify Requirement R3.1, which currently requires that a balancing authority to carry at least enough contingency reserves to cover ''the most severe single contingency.'' The Commission proposed to change the Requirement to include enough contingency reserves to cover any event or single contingency, including a transmission outage, which results in a significant deviation in frequency from the loss or mismatch of supply either from local generation or imports. The Commission noted that this approach would address staff's concern with Requirement R3.1—specifically, addressing the ambiguity over whether the Requirement meant the loss of generation or the loss of supply resulting from a transmission or generation contingency.[161]

347. Most commenters [162] express concern over the Commission's proposal to add a Requirement that measures response for any event or contingency that causes a frequency deviation. NERC states that this proposed directive is overly prescriptive and suggests that an improved modification would be to direct the ERO to resolve the ambiguity

[158] *See* APPA, International Transmission, MISO–PJM, LPPC and California PUC.

[159] NOPR at P 156.

[160] Although Frequency Response and Bias are

[161] NOPR at P 153.

[162] *See* NERC, APPA, Xcel, MRO, ISO–NE, EEI and Nevada Companies.

in Requirement R3.1 as pointed out in the Staff Preliminary Assessment. APPA suggests that the Commission should not require NERC to modify the Reliability Standard, but should allow NERC to address the Commission's concerns in its Reliability Standards development process and, while doing so, NERC should consider defining ''Most Severe Single Contingency'' contained in the WECC Frequency Response Standard White Paper.[163] Xcel has concerns about the compliance aspects of this proposed modification stating that there is no equitable method to assess an individual entity's performance for an occurrence that is potentially Interconnection-wide.

348. NRC notes the NERC and Commission observations regarding the declining trend in frequency response and states that this Reliability Standard provides the opportunity to establish a frequency response performance standard. NRC staff suggests that a Measure be added to establish a frequency response.

349. MRO suggests that, if this requirement is adopted, a clear definition of the event that causes a frequency deviation will be required. ISO–NE comments that Requirement R3.1 is already clear and the suggested modification is not clear because: (1) It is not possible to plan for all such events and (2) it is not clear what is a ''significant deviation.'' EEI states that a requirement to measure frequency response for any event or contingency could provide beneficial information for system operators but states that there is presently no requirement for generators to report all outages so measurements cannot be made. EEI further states that the compliance costs of this requirement may outweigh the benefits. The Nevada Companies disagree with the proposed modification and state that the Reliability Standard must instead focus strictly on the loss of supply. The Nevada Companies further state that, for purposes of this Reliability Standard, WECC's present contingency reserve criterion, which requires consideration of loss of generation that would result from the most severe single contingency, is most applicable.

350. Georgia Operators comment that the Commission's intent in this proposed modification should not be interpreted to require a balancing authority to carry enough reserves to cover any event resulting in a significant deviation in frequency and should not be read to suggest that frequency rather than ACE should be used to measure a balancing authority's deployment of reserves for contingencies.

351. MISO and ERCOT comment on the Commission's suggestion that NERC should consider defining a frequency deviation of 20 milli Hertz lasting longer than the 15 minute recovery period as a significant deviation. MISO argues that the value could vary in different Interconnections and believes the current method is acceptable. ERCOT states that it is not feasible to apply a single frequency-deviation number to ERCOT and the other Interconnections and asks the Commission to instead consider a Reliability Standard that is proportional to the size of each Interconnection. ERCOT notes that 20 milli Hertz would be far more strict than ERCOT's historic frequency performance.

(b) Commission Determination

352. On this issue, the Commission will not direct the ERO to modify BAL–002–0 in the manner proposed in the NOPR. Rather, the Commission directs the ERO to address the concerns expressed by the Commission about having enough contingency reserves to respond to an event on the system in Requirement R3.1 and how such reserves are measured. The ERO should address this through adoption or modification of Requirements and metrics in the Reliability Standards development process.

353. NERC correctly points out that the Commission's proposal on this point stemmed from the ambiguity in Requirement R3.1 that Commission staff highlighted in the Staff Preliminary Assessment. Requirement R3.1 currently requires that a balancing authority carry at least enough contingency reserves to cover ''the most severe single contingency.'' The Commission emphasizes that the goal of this Reliability Standard is to insure against the reliability risk of not serving load by matching generation and load following any disturbance or event that results in a significant deviation in frequency. Consistent with this goal, the Commission believes that this Reliability Standard should be inclusive of all events, *i.e.*, loss of supply, loss of load or significant scheduling problems, which can cause frequency disturbances and should address how balancing authorities should respond. The Commission notes that PJM recently issued a paper addressing frequency excursion related to scheduling problems.[164]

354. In the NOPR, the Commission identified two concerns in the Disturbance Control Standard section of BAL–002–0. The first discussed NERC's comment that the Reliability Standard is ''absolute, objective, and measurable'' because it allows up to 15 minutes for the recovery from a reportable disturbance,[165] and second, the Commission asked whether a frequency deviation of 20 milli Hertz lasting longer than the 15 minute recovery period should be used to define a significant deviation in frequency.[166] No commenters address the first concern but many commented on the second.

355. First, the Commission directs the ERO to develop a modification to the Reliability Standard requiring that any single reportable disturbance that has a recovery time of 15 minutes or longer be reported as a violation of the Disturbance Control Standard. This is consistent with our position in the NOPR and NERC's position in response to the Staff Preliminary Assessment of the Requirements in BAL–002–0, and was not disputed or commented upon by any NOPR commenters.

356. Taking into account commenters' concerns about defining a significant deviation as a frequency deviation of 20 milli Hertz lasting longer than the 15 minute recovery period, the Commission will not direct a specific change. Instead, we direct the ERO, through the Reliability Standards development process, to modify this Reliability Standard to define a significant deviation and a reportable event, taking into account all events that have an impact on frequency, *e.g.*, loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances and to address how balancing authorities should respond. As suggested by NRC, this or a related Reliability Standard should also include a frequency response requirement. The present Control Performance Standards represent the monthly and yearly averages which are appropriate for measuring long-term trends but may not be appropriate for measuring short-term events. In addition, the measures should be available to the balancing authorities to assist in real-time operations.[167]

vi. Summary of Commission Determination

357. The Commission approves Reliability Standard BAL–002–0 as

[163] *See* NOPR at n.116.

[164] *Id.* at n.134.

[165] NERC Comments on the Staff Preliminary Assessment at 41.

[166] NOPR at P 153.

[167] It is the Commission's understanding that the Balancing Authority ACE Limit Standards that are currently being field tested are triggered on frequency deviations and can be used as feedback to the real-time operations personnel.

mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL–002–0 through the Reliability Standards development process that: (1) Includes a Requirement that explicitly provides that DSM may be used as a resource for contingency reserves; (2) develops a continent-wide contingency reserve policy;[168] and (3) refers to the ERO rather than the NERC Operating Committee in Requirements R4.2 and R6.2. In addition, the Commission directs the ERO to modify the Reliability Standard in a manner that recognizes the loss of transmission as well as generation, thereby providing a realistic simulation of possible events that might affect the contingency reserves.

d. Frequency Response and Bias (BAL–003–0)

358. The purpose of BAL–003–0 is to ensure that a balancing authority's frequency bias setting [169] is accurately calculated to match its actual frequency response.[170] In the NOPR, the Commission proposed to approve Reliability Standard BAL–003–0 as mandatory and enforceable. In addition, pursuant to section 215(d) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to BAL–003–0 that: (1) Includes Levels of Non-Compliance and (2) modifies Measure M1 to include yearly surveys of frequency response.[171]

359. The Commission further requested comments on whether BAL–003–0 appropriately addresses frequency bias setting during normal as well as emergency conditions and whether a requirement should be added for balancing authorities to calculate the frequency response necessary for reliability in each of the Interconnections and identify a method of obtaining that frequency response from a combination of generation and load resources.[172]

i. Comments

360. Several commenters address the Commission's proposal to direct the ERO to modify Measurement M1 to include yearly surveys.

361. LPPC agrees with the Commission's proposed directive. EEI states that NERC currently conducts an annual frequency response characteristic survey that appears to address the Commission's proposed directive. If the yearly survey would replace the frequency response characteristic survey, EEI states that the survey should include questions regarding the scope of potential new requirements. ISO/RTO Council believes that yearly surveys are unnecessary and would prefer that NERC focus on surveying balancing authority responses to large frequency disturbances.

362. APPA agrees that the Commission has correctly identified shortcomings in this Reliability Standard and states that, while the Commission may have identified appropriate modifications, the determination should be left to NERC to address in the first instance. APPA supports the development of a consistent Interconnection-wide policy and suggests that NERC should consider procedures similar to those used in ERCOT and WECC.

363. FirstEnergy suggests that Requirements R5 and R5.1 of this Reliability Standard should be required in lieu of Requirement R2 if a balancing authority has load but no generation (R5) or if a balancing authority has generation but no load (R5.1). FirstEnergy states that without this change the Reliability Standard is not clear because it implies that a balancing authority could choose between two options. Most commenters responded to the Commission's request for comments in the NOPR by stating that additional requirements do not need to be added for balancing authorities to calculate the frequency response necessary for reliability in each of the Interconnections. NERC states that frequency bias is currently over-compensated across the Interconnections and that requiring frequency bias to be actual frequency response may reduce control performance. Additionally, NERC states that some studies have shown a decline in frequency (*e.g.*, governor) response over several decades and that it is addressing this issue through the request for a new Reliability Standard on frequency response. NERC also notes that BAL–003–0 will be replaced soon by the new balancing Reliability Standards that are approaching ballot.

364. In general, EEI believes that systemic over-biasing does not present a reliability problem and the Commission should exercise caution in requesting changes to this Reliability Standard. EEI states that the frequency bias varies continuously in terms of the type and magnitude of load changes, and the types and loading of generation resources. Therefore, EEI suggests that the accuracy of any estimate of frequency bias is highly questionable. Further, EEI states that the one percent default value was deliberately set to over-bias the system to ensure adequate frequency response. EEI is unaware of any evidence of undamped oscillations due to this over-biasing and states that the one percent floor should be recognized by the Commission as just and reasonable until an optimum frequency bias value can be studied. EEI sees the potential need for developing requirements for modifying frequency bias during emergency conditions, citing evidence from the August 2003 blackout suggesting that oscillations following the ISO New England separation from the Eastern Interconnection may have been caused by over-biasing.

365. ISO/RTO Council comments that the details of the procedures that are used to ensure frequency bias are appropriate and no additional requirements for balancing authorities are needed. It disagrees with the Commission's proposal to develop uniform requirements for frequency bias.[173] ISO/RTO Council states that there is no single right way to develop and apply a frequency bias setting and no universally accepted norm. ISO/RTO Council believes the key point is that the frequency bias setting be greater than the natural frequency response of the system and believes that the percent minimum currently in place is sufficient. ISO/RTO Council recommends that NERC investigate (1) reliability issues associated with low natural response; (2) causes of decreasing natural response and (3) possible opportunities for creating markets for load and generator response to frequency changes.

366. Xcel responds that there is no need for this Reliability Standard to address frequency bias during black start, restoration and islanding due to the transitional nature of those events. Northern Indiana opposes imposing greater restrictions on frequency bias and frequency response calculations, stating that they could be counter-productive by making procedural errors more likely, which could harm reliability. Northern Indiana suggests that the approach suggested in the NOPR would require frequency

[168] This could be accomplished by modifying Requirement R2 or developing a new Reliability Standard.

[169] Frequency bias setting is a value expressed in MW/0.1 Hz, set into a balancing authority ACE algorithm, which allows the balancing authority to contribute its frequency response to the Interconnection. *See* NERC glossary at 7.

[170] The actual frequency response is the increase in output from generators after the loss of a generator and determines the frequency at which generation and load return to balance.

[171] NOPR at P 177.

[172] *Id.* at P 175.

[173] *See id.* at P 129.

response to be calculated based on various contingencies in a way that, if a particular contingency does not occur, the balancing authority might contribute to an incorrect frequency response. Northern Indiana maintains that the existing Reliability Standard is appropriate because it reflects the unique characteristics of each utility's operating characteristics and allows experienced, certified operators to act to avoid adverse effects on the electric system.

367. MidAmerican believes that a requirement for balancing authorities to calculate the necessary frequency response is not necessary for reliability, nor should balancing authorities be required to identify the method to obtain that frequency response. MidAmerican states that the bias settings addressed in BAL–003–0 are appropriate for normal and emergency conditions. It further explains that large disturbances resulting in large frequency shifts can only be corrected by bringing load and generation into balance. MidAmerican further states that the annual review of bias settings uses tie line and frequency deviations during large disturbances to provide bias settings representative of relatively large frequency excursions and adds that these settings, along with automatic generation control and governor response, provide an over-biased response to steady-state frequency deviations. MidAmerican states that as long as system disturbances are continually tracked to ensure frequency decay is sufficiently mitigated, enough frequency bias will be on the system and the current Reliability Standard can be considered sufficient.

368. MISO states that it expects the Commission's concerns with the frequency response and bias standard to be addressed in NERC's frequency response Reliability Standard Authorization Request.

ii. Commission Determination

369. The Commission approves Reliability Standard BAL–003–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL–003–0 as discussed below.

370. With respect to the frequency of frequency response surveys, EEI states that NERC currently conducts an annual frequency response characteristic survey that appears to address the Commission's concern. The Commission disagrees. The surveys that were performed on a yearly basis are not available on NERC's Web site and the ISO/RTO Council believes that more frequent analysis after large frequency disturbances is appropriate. The Commission understands that the last analysis was performed in 2002. Currently, Measure M1 only requires balancing authorities to perform surveys when requested by the NERC operating committee. As identified in Order No. 672, the Reliability Standards should be based on actual data.[174] Therefore, on further consideration, instead of requiring yearly surveys as proposed in the NOPR, the Commission believes that the frequency of these surveys should be based on the data requirements that will assist the ERO to determine if the balancing authorities are providing adequate and equitable frequency response to disturbances on the Bulk-Power System. Accordingly, we direct the ERO to determine the optimal periodicity of frequency response surveys necessary to ensure that Requirement R2 and other Requirements of the Reliability Standard are being met and to modify Measure M1 based on this determination.[175]

371. With respect to FirstEnergy's comment, Requirement R2 states that the frequency bias setting should be as close as practical to, or greater than, the balancing authority's frequency response. That is the Requirement concerning the relationship between frequency response and frequency bias, with Requirement R5 and R5.1 providing minimum frequency bias values for specific types of balancing authorities. The three Requirements do not conflict. A balancing authority must use a frequency bias of at least one percent and they must have a frequency bias that is as close as practical to, or greater than, the balancing authority's actual frequency response. As will be discussed more fully below, the Commission expects each balancing authority to meet these Requirements to be in compliance with the existing BAL–003–0.

372. With respect to the Commission's request for comments, most commenters are opposed to additional requirements for balancing authorities to calculate the frequency response necessary for reliability in each of the Interconnections. NERC states that frequency bias is currently over-compensated across the Interconnections, while EEI states that the one percent default value was deliberately set to over-bias the system to ensure adequate Frequency Response. The ISO/RTO Council comments that frequency bias settings are appropriate and all agree that no additional requirements are needed. However, NERC acknowledges that the frequency response of the Eastern and Western Interconnection is decreasing and states it will address the issue with a new frequency response Reliability Standard. There is no similar need in ERCOT because ERCOT has adopted an approach to calculate the necessary frequency response needed for Reliable Operation and has identified a method of obtaining the necessary frequency response as discussed in BAL–001–0 regional difference. The Commission understands that this approach was based on lessons learned from the May 15, 2003 event[176] that resulted in larger than anticipated amounts of firm load shedding by underfrequency relays operation due to less than desirable amounts of frequency response.

373. The Commission is not persuaded by the commenters. We conclude that the minimum frequency response needed for Reliable Operation should be defined and methods of obtaining the frequency response identified. In addition to the ERCOT experience, EEI provides an additional example that underscores the Commission's concern in this area with its discussion of the ISO–NE frequency oscillations resulting from the August 14, 2003 blackout. Severe oscillations were observed in the ISO–NE frequency when it separated from the Eastern Interconnection during the August 14, 2003 blackout.[177] The ISO–NE operators acted quickly to reduce the bias setting so as to eliminate the self-induced frequency oscillations before they affected system reliability. This apparent mismatch between the bias and the actual frequency response might have caused the ISO–NE system to cascade if it had not been for the quick actions of its operators. Therefore, we direct the ERO to either modify this Reliability Standard or develop a new Reliability Standard that defines the necessary amount of frequency response needed for Reliable Operation and methods of obtaining and measuring that frequency response is available.

374. As the Commission noted in the NOPR and in our response to FirstEnergy, Requirement R2 of this

[174] Order No. 672 at P 324.

[175] As input to the Reliability Standards development process, the Commission suggests that the ERO perform sufficient analysis to understand how the frequency response varies between balancing authorities and Interconnections.

[176] *See* Underfrequency Load Shedding 2006 Assessment and Review by ERCOT Dynamics Working Group, available at *http://www.ercot.com/meetings/ros/keydocs/2007/0111/10a._DWG_2006_UFLS_Assessment_12-18-06.doc.*

[177] *See* Performance of the New England and Maritimes Power Systems During the August 14, 2003 Blackout by Independent System Operator New England, available at *https://www.npcc.org/publicFiles/blackout/archives/Restoration_of_the_NPCC_Areas.pdf.*

Reliability Standard states that ''[e]ach Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response.'' The Commission believes that the achievement of this Requirement is fundamental to the tie line bias control schemes that have been in use to assist in balancing generation and load in the Interconnections for many years.[178] We understand that the present Reliability Standard sets the required frequency response of the balancing authorities to be approximately one percent or greater by requiring that the frequency bias shall not be less than one percent and that the frequency bias be as close as practical to, or greater than, the actual frequency response.

375. While EEI supports additional requirements related to frequency bias during emergency conditions, Xcel states that frequency response during black start, restoration and islanding situations need not be addressed in a Reliability Standard due to the transient nature of these events. The Commission disagrees with Xcel and agrees with EEI. The Bulk-Power System should be operated in a reliable manner at all times.

376. Accordingly, the Commission approves Reliability Standard BAL–003–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL–003–0 through the Reliability Standards development process that: (1) Includes Levels of Non-Compliance; (2) determines the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) defines the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved.

e. Time Error Correction (BAL–004–0)

377. The purpose of BAL–004–0 is to ensure that time error corrections are conducted in a manner that does not adversely affect the reliability of the Interconnection.[179] In the NOPR, the Commission proposed to approve Reliability Standard BAL–004–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to BAL–004–0 that includes Levels of Non-Compliance and additional Measures.[180]

378. Further, the Commission noted that WECC has implemented an automatic time error correction procedure [181] that, according to data on the NERC Web site, is more effective in minimizing both time error corrections and inadvertent interchange.[182] The NOPR asked for comment on whether the Commission should require NERC to adopt Requirements similar to those in the WECC automatic time error correction procedure.

i. Comments

379. MISO states that it is unclear what the Commission had in mind with its proposed directive to include Levels of Non-Compliance and additional Measures and that the reliability benefit of such Levels of Non-Compliance and additional Measures is also unclear.

380. While APPA and EEI favor adopting the WECC approach to time error correction, NERC and the majority of other commenters [183] are either opposed to adopting the WECC automatic time error correction procedure in other regions or think time error correction is more appropriately addressed as a business practice. NERC notes that the WECC procedure is in lieu of an equivalent procedure contained within the business practices of the North American Energy Standards Board (NAESB) and suggests that instructions for implementing a time error correction are more appropriately addressed as a business practice. Northern Indiana maintains that WECC-type procedures are unnecessary, and could result in unintended process errors or operational problems. It urges the Commission to allow time error issues to remain within the jurisdiction of NAESB and suggests that time error correction is not essential to reliability and is more appropriately treated as a non-essential guide. ISO–NE agrees that time error correction is not a reliability issue.

381. Xcel states that its operating company located in WECC has experienced problems with WECC's automatic time error correction procedure and therefore does not support adoption of this procedure by other regions. In addition, Xcel states that time error correction is not necessary for utilities in regional markets where imbalances are settled financially and the regional market operator manages the scheduled interchange offsets. LPPC suggests that there is not enough evidence to show that WECC's time error correction procedure is appropriate for the Eastern Interconnection. LPPC adds that the choice of switching to the WECC procedure should be left up to the NERC Reliability Standards development process.

382. MISO states that, while the WECC procedure has advantages with regard to reducing inadvertent interchange values, it does not reduce the number of time error corrections because WECC monitors and performs time error correction on a shorter time frame than the Eastern Interconnection. MISO argues that this is more of a technical requirement and not a Reliability Standard and suggests there are simpler ways to control time error and manage inadvertent balances. MISO states that NERC previously allowed unilateral payback of inadvertent balance of up to 20 percent of bias when the payback is in a direction to reduce time error and states that this reduced the number of time error corrections while giving balancing authorities a tool to balance their accounts. In its comments addressing BAL–006–1, MISO suggests that the number of time error corrections could be reduced by following the European methodology which has a wider window of allowable time and implements full clock-day, but with a smaller offset.

ii. Commission Determination

383. The Commission approves Reliability Standard BAL–004–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL–004–0 through the Reliability Standards development process that includes Levels of Non-Compliance and additional Measures for Requirement R3. Further, based on commenters' concerns that there is no engineering basis for changing the time error correction to the WECC approach or any other approach, when reviewing the Reliability Standard during the ERO's scheduled five-year cycle of review, we direct the ERO to perform

[178] Cohn, Nathan, *Control of Generation and Power Flow on Interconnected Systems*, (John Wiley and Sons 1966).

[179] The NERC glossary defines ''time error correction'' as ''an offset to the Interconnection's scheduled frequency to return the Interconnection Time Error to a predetermined value.'' NERC Glossary at 18. Time error is caused by the accumulation of frequency error over a given period.

[180] NOPR at P 184.

[181] See *http://www.wecc.biz/documents/library/procedures/Time_Error_ Procedure_10-04-02.pdf.*

[182] See *http://www.nerc.com/~filez/inadv.html* (regarding inadvertent interchange data) and *http://www.nerc.com/~filez/timerror.html* (regarding time error correction).

[183] *See* Xcel, Northern Indiana, ISO–NE, LPPC and MISO–PJM.

research that would provide a technical basis for the present approach or for any alternative approach.

384. Many commenters aver that the time error correction procedure belongs within the realm of NAESB and is not a reliability issue. The Commission disagrees, as BAL–004–0 is intended to ensure that time error corrections are performed in a manner that does not adversely affect the reliability of the Interconnection. The financial aspects of time error correction such as MISO's concern about the unilateral payback of interchange imbalances remain with NAESB. However, the technical details, including the means to carry out the procedure, are a reliability issue.

385. We believe that the efficiency of the time error correction can be viewed as a measure of whether all balancing authorities are participating in time error correction. Requirement R3 states that each balancing authority, when requested, shall participate in a time error correction. The Commission believes that this is a critical requirement, but the data on the NERC Web site indicates that efficiency is decreasing, indicating that fewer balancing authorities are employing time error correction.[184] Therefore, the Commission affirms its preliminary finding that the efficiency of time error corrections has decreased over the last ten years and that participation in time error corrections may be lacking.[185] Accordingly, we direct the ERO to develop additional Measures and add Levels of Non-Compliance to assure that the requirements in Requirement R3 are achieved. One approach to achieving this would be to use the existing measurement of efficiency as a metric of participation of all balancing authorities. If the efficiency is significantly less than 100 percent, the Measures should provide a process to identify which balancing authorities are not meeting the requirements of the Reliability Standard.

386. Although the Commission noted in the NOPR that WECC's time error correction procedure appears to serve as a more effective means of accomplishing time error correction, based on concerns that there is no engineering basis for changing the time error correction to the WECC approach, the Commission will not direct the ERO to adopt requirements similar to WECC's procedure. With the exception of comments from APPA and EEI, most commenters do not believe or are uncertain about whether the WECC procedure is appropriate for the Eastern Interconnection. However, when this Reliability Standard is scheduled for its regular five-year cycle of review, the Commission directs the ERO to perform whatever research it and the industry believe is necessary to provide a sound technical basis for either continuing with the present practice or identifying an alternative practice that is more effective and helps reduce inadvertent interchange.

387. The Commission agrees with MISO regarding the number of time error corrections using WECC's procedure. However, the magnitude of the frequency change in the WECC automatic time error correction is smaller than the manual correction and timing of the corrections are better correlated to when the error was created. These two characteristics of the WECC procedure avoid placing the system in less secure conditions and tie the payback to the initiating action, both of which appear to better serve both reliability and equity.

f. Automatic Generation Control (BAL–005–0)

388. The goal of this Reliability Standard is to maintain Interconnection frequency by requiring that all generation, transmission, and customer load be within the metered boundaries of a balancing authority area, and establishing the functional requirements for the balancing authority's regulation service, including its calculation of ACE.

389. In the NOPR, the Commission proposed to approve Reliability Standard BAL–005–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to BAL–005–0 that: (1) Includes Requirements that identify the minimum amount of automatic generation control or regulating reserves a balancing authority must have at any given time; (2) changes the title of the Reliability Standard to be neutral as to source of the reserves; (3) includes DSM and direct control load management as part of contingency reserves and (4) includes additional Levels of Non-Compliance and Measures, including a Measure that provides for a verification process over the minimum required automatic generation control or regulating reserves a balancing authority maintains.[186]

390. Further, the NOPR stated that the Commission is interested in knowing whether any balancing authority is experiencing or is predicting any difficulty in obtaining sufficient automatic generation control.

i. Minimum Amount of Regulating Reserves

(a) Comments

391. South Carolina E&G and SMA support the Commission's proposal to include a requirement that addresses minimum regulating reserves. It states that the control performance standard metric is a lagging indicator of necessary reserves and other standards such as frequency response may eventually provide a more dynamic real-time indicator. South Carolina E&G believes the Commission's proposal provides a good interim solution.

392. Alcoa comments that, in establishing a minimum amount of reserves, NERC should be required to consider the quality of each source of reserves. Alcoa suggests that digitally controlled DC loads, such as an aluminum smelter, could respond much more rapidly and accurately than thermal generators and that using such resources could reduce the response time for recovery, allowing thermal units to carry fewer spinning reserves and increasing operating efficiencies of the grid.

393. NERC and other commenters[187] suggest that the Commission's proposed directive to have NERC include ''Requirements that identify the minimum amount of automatic generation control or regulating reserves a balancing authority must have at any given time'' is too prescriptive. They also object to this proposed requirement since a balancing authority's failure to maintain sufficient regulating reserves will result in violations of control performance standard criteria already found in BAL–001–0.

394. NERC further states that a requirement to have a minimum amount of regulating reserves would result in an arbitrary constraint that would not add to reliability and suggests that the Commission instead direct NERC to consider the issue of a minimum requirement in its Reliability Standards process in order to determine the reliability benefit.

395. EEI states that the industry currently has no consensus-based, sound engineering methodology for determining a minimum regulating reserve requirement given widely varying needs throughout the country.

[184] *See* W.R. Prince, et al., *Cost Aspects of AGC, Inadvertent Energy and Time Error*, IEEE Transactions on Power Systems, February 1990, at 111.

[185] NOPR at P 179, 183.

[186] NOPR at P 197.

[187] *See* APPA, EEI, International Transmission, MISO–PJM, MidAmerican and LPPC.

Nonetheless, EEI offers several guidelines that it says could be used to provide estimates for minimum regulating reserves. Similarly, MidAmerican states that normal regulating margins can vary from one balancing authority to another, and even within one balancing authority, due to frequently changing load characteristics making it extremely difficult to quantify an hourly required level of reserves. MidAmerican suggests that instead of prescriptively quantifying reserve levels, the ERO should continue to allow the industry to find efficient ways to comply with the control performance standards of BAL–001–0.

396. FirstEnergy suggests that a single entity should have the responsibility to establish, through an annual review process, the level of regulating reserves that a balancing authority must maintain pursuant to the control performance standard requirements. FirstEnergy suggests that all generators and technically qualified DSM that participate in energy markets should install automatic generation control as a condition of market participation. In non-market areas, FirstEnergy suggests that balancing authorities could meet requirements through bilateral contracts or the normal scheduling process and suggests that the Commission might have to assert its jurisdiction and order technically qualified DSM providers to install automatic generation control at their facilities. FirstEnergy states that further work would need to be conducted on the technical qualifications and capacity thresholds that would control whether installation of automatic generation control would be required.

(b) Commission Determination

397. On this issue, the Commission directs the ERO to modify BAL–005–0 through the Reliability Standards development process to develop a process to calculate the minimum regulating reserve for a balancing authority, taking into account expected load and generation variation and transactions being ramped into or out of the balancing authority.

398. As a general matter, the Commission believes that a single entity should establish the level of regulating reserve required based on the generation mix and ramping rates in the region. We disagree with commenters that minimum regulating reserve requirements are not necessary. As South Carolina E&G correctly points out, the control performance standard metric is a lagging indicator and, as such, does not provide a good indication that the necessary amounts of regulating reserve are being carried at all times. The Commission notes that Requirement R2 requires maintenance of a level of regulating reserves in order to prospectively meet the control performance standard but does not provide a calculation for the exact level which would be required. In particular, the Commission believes that, while the control performance standard metric is useful in identifying trends relating to poor regulating practices, specification of minimum reserve requirements to be maintained at all times would complement the control performance standard metrics by providing real-time requirements necessary for proper control.

399. With regard to Alcoa's comment, the Commission agrees that the quality of reserves is relevant in determining if the resource is able to technically qualify as regulation.

400. Nevertheless, the Commission recognizes commenters' concerns related to the calculation of minimum regulation. EEI has offered several possible methods to calculate the minimum amount of regulation needed for reliability, which may or may not be consistent with others in the industry. The fundamental reason for regulating reserves is to balance load and generation in the short term due to the random variations in the balancing authorities' loads and to accommodate ramping of transactions. The Commission therefore directs the ERO to develop a process to calculate the minimum regulating reserve for a balancing authority, taking into account expected load and generation variation and transactions being ramped into or out of the balancing authority.

ii. Title Change and Inclusion of DSM.

(a) Comments

401. As an initial matter, many commenters express confusion about the Commission's proposal to require NERC to change the title of the Reliability Standard to be neutral as to the source of the reserves, and include DSM and direct control load management as part of contingency reserves.[188] In particular, these commenters argue that this Reliability Standard pertains to regulating reserve and not contingency reserves.

402. Constellation agrees with the Commission that DSM and direct control load management should be included as viable options for regulating reserves.[189] MidAmerican agrees with the Commission on the proposed title change to allow it to be neutral as to the source of reserves but cautions the Commission on including DSM as a source of contingency reserves. While MidAmerican believes it proper to include direct control load management, which is under direct control of the system operator in contingency reserves, it states that the term DSM (as defined in the NERC glossary) is too general and includes programs that cannot contribute toward contingency reserves.

403. APPA and International Transmission both disagree with the Commission's proposals to change the title of this Reliability Standard and to include DSM and direct control load management. APPA suggests that DSM and direct control load management are not operationally equivalent to dispatchable generation resources and does not believe these programs are an effective source of regulating reserve given the current state of technology. International Transmission simply states that regulating reserves required by BAL–005–0 are specifically responsive to automatic generation control.

404. ISO–NE disagrees with the Commission's proposal to include DSM and direct control load management as part of this service, stating that responsive load has not demonstrated the load following capability necessary to provide regulation and that it is not aware of any load-based resources that can closely follow automatic generation control signals sent every four seconds. As an alternative to the Commission's approach, ISO–NE suggests that the Reliability Standard should define the reliability purpose or objective and then be resource-neutral.

(b) Commission Determination

405. At the outset, the Commission agrees with commenters that this Reliability Standard applies to regulating reserves and not contingency reserves. The references to contingency reserves under this Reliability Standard in the NOPR are confusing. The Commission clarifies that its direction to the ERO in this section is for it to develop a modification to BAL–005–0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and allows the inclusion of technically qualified DSM and direct

[188] EEI, TVA, International Transmission, Multiple Interveners, MISO–PJM, South Carolina E&G and Wisconsin Electric.

[189] Since the Commission used the term ''contingency reserves'' inappropriately in this section, we assume that Constellation intended this to be regulating reserves.

control load management as regulating reserves, subject to the clarifications provided in this section.

406. We disagree that it is not possible to use DSM and direct control load management as a source of regulating reserves or any other type of operating reserves. The Commission notes that, while DSM and direct control load management may not be widely used today as a source of operating reserves, comments received and other evidence suggest that certain types of loads are technically capable of providing this service. For example, comments received from Alcoa suggest that certain loads, such as digitally controlled DC loads, are capable of responding much faster than generation to a reserve need.

407. Given that most of the commenters' concerns over the inclusion of DSM as part of regulating reserves relate to the technical requirements, the Commission clarifies that to qualify as regulating reserves, these resources must be technically capable of providing the service. In particular, all resources providing regulation must be capable of automatically responding to real-time changes in load on an equivalent basis to the response of generation equipped with automatic generation control. From the examples provided above, the Commission understands that it may be technically possible for DSM to meet equivalent requirements as conventional generators and expects the Reliability Standards development process to provide the qualifications they must meet to participate. These qualifications will be reviewed by the Commission when the revised Reliability Standard is submitted to the Commission for approval.

iii. Whether Balancing Authorities Are Experiencing or Predicting Difficulty in Obtaining Sufficient Automatic Generation Control

(a) Comments

408. Constellation states that its ability to obtain regulating reserves is hampered by a lack of resources that qualify as regulation and the practices that some transmission service providers have adopted in implementing dynamic transfers needed to procure regulating reserves from other balancing authorities. In particular, Constellation states that many transmission service providers impose a requirement that regulation services must be provided using firm transmission. Constellation suggests that purchasing regulation from another balancing authority using non-firm transmission service is allowed under the Reliability Standards and that Requirement R5 of BAL–005–0 provides that balancing authorities must have back-up plans to provide replacement regulation service if the purchased regulation service is lost. Constellation requests that the Commission clarify that the transmission providers may not impose a requirement to rely exclusively on firm transmission for the dynamic transfers of regulating reserves.

(b) Commission Determination

409. In response to Constellation's concerns, the Commission notes that, if regulation is being provided over non-firm transmission service, the entity receiving the regulation should be responsible for having a back-up plan to include loss of the non-firm transmission service as referenced in Requirement R5. The Commission believes that a balancing authority may use non-firm transmission service for procuring regulation, so long as that balancing authority has a back-up plan that it can implement to include loss of non-firm transmission service.

iv. Other Comments

(a) Comments

410. MISO states that it is uncertain of the basis of the claim that there have been an increased number of ''[automatic generation control] controllable'' frequency excursions.[190] MISO further states that data in the Eastern Interconnection shows the number of larger-slower excursions has decreased over the past few years.

411. Xcel requests that the Commission reconsider Requirement R17 of this Reliability Standard stating that the accuracy ratings for older equipment (current and potential transformers) may be difficult to determine and may require the costly replacement of this older equipment on combustion turbines and older units while adding little benefit to reliability. Xcel states that the Commission should clarify that Requirement R17 need only apply to interchange metering of the balancing area in those cases where errors in generating metering are captured in the imbalance responsibility calculation of the balancing area.

412. FirstEnergy states that Requirement R17 should include only ''control center devices'' instead of devices at each substation. FirstEnergy states that accuracy at the substation level is unnecessary and the costs to install automatic generation control equipment at each substation would be high. FirstEnergy also states that the term ''check'' in Requirement R17 needs to be clarified.

413. California Cogeneration states that the Commission has previously ruled that separate metering for the gross generation of a customer-owned generator is not proper or necessary, and states that the Commission should clarify that this Reliability Standard does not establish metering requirements for individual generators, and does not allow separate metering of generation and load on an end-user's site.[191]

414. LPPC notes that BAL–005–0 has 17 requirements but no Measures, and that it uses phrases such as ''adequate metering'' and ''burden on the interconnection.'' LPPC contends that there is no definition for these ambiguous terms and that there is no way to determine if terms like ''adequate metering'' will mean the same thing in different parts of the country or ensure consistent penalties will be assessed for the same violation.

(b) Commission Determination

415. The Commission agrees with MISO that, while the number of frequency deviations due to loss of generation has decreased, the Commission is concerned with the implications of the actual data presented by PJM that shows two frequency deviations each week day without the loss of generation.[192] This concern is supplemented by documents that identify that some balancing authorities are restricting automatic generation control actions during schedule changes.[193]

416. Both Xcel and FirstEnergy question Requirement R17 but do not oppose the Commission's proposal to approve this Reliability Standard. Earlier in this Final Rule, we direct the ERO to consider the comments received to the NOPR in its Reliability Standards development process. Thus, the comments of Xcel and FirstEnergy should be addressed by the ERO when this Reliability Standard is revisited as part of the ERO's Work Plan.

417. California Cogeneration requests clarification that Commission rulings made prior to the enactment of FPA section 215 would still be applicable. The case cited by California Cogeneration was issued before EPAct 2005 was enacted and gave the Commission direct responsibility over

[190] NOPR at P 194.

[191] *See* California Cogeneration at 6, citing *California Independent System Operator Corp.*, Opinion No. 464, 104 FERC ¶ 61,196 (2003).

[192] NOPR at n.134.

[193] *See* R. L. Vice, *Frequency Issues 2005*, available at: *http://www.wecc.biz/documents/library/RITF/Frequency_Issues_2005_rev_0.pdf.*

Bulk-Power System reliability. By its terms, BAL–005–0 requires each generator operator with generating facilities operating within an Interconnection to ensure that those generating facilities are included within the metered boundaries of a balancing authority area. Therefore, any generator that is subject to the Reliability Standards, as discussed in the Applicability Issues section of this Final Rule,[194] is subject to the metering requirements in this Reliability Standard. Our conclusion, however, does not determine the appropriate ratemaking treatment.

418. With respect to LPPC's concern that terms used in the Reliability Standard are not definitive when viewed individually, and LPPC's statement that the Reliability Standard is ambiguous because it does not include Measures, we disagree. The Commission finds each Requirement of BAL–005–0 is clear and enforceable. The Requirements provide sufficient guidance for an entity to understand its obligations. When Measures are incorporated into the Reliability Standard, the Measures will provide guidance on assessing non-compliance with the Requirements. For these reasons and as previously addressed in the NOPR, the Commission disagrees that the enforceable obligations set forth in Requirements are unclear absent Measures.

419. The Commission notes that no one commented on the proposal to include Levels of Non-Compliance and Measures, including a Measure that provides for a verification process over the minimum required automatic generation control or regulating reserves a balancing authority maintains. The Commission adopts the NOPR proposal to require the ERO to modifiy the Reliability Standards to include a Measure that provides for a verification process over the minimum required automatic generation control or regulating reserves a balancing authority maintains. However, as discussed in the Common Issues section of this Final Rule, we will leave it to the discretion of the ERO whether to include other Measuers.[195]

420. FirstEnergy has a number of suggestions to improve the existing Reliability Standard and the ERO is directed to consider those suggestions in its Reliability Standards development process.

v. Summary of Commission Determinations

421. The Commission approves Reliability Standard BAL–005–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL–002–0 through the Reliability Standards development process that: (1) Develops a process to calculate the minimum regulating reserve a balancing authority must have at any given time taking into account expected load and generation variation and transactions being ramped into or out of the balancing authority; (2) changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and to allow the inclusion of technically qualified DSM and direct control load management; (3) clarifies Requirement R5 of this Reliability Standard to specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using non-firm service and (4) includes Levels of Non-Compliance and a Measure that provides for a verification process over the minimum required automatic generation control or regulating reserves a balancing authority must maintain.

g. Inadvertent Interchange (BAL–006–1)

422. BAL–006–1 requires that each balancing authority calculate and record inadvertent interchange on an hourly basis.

423. In the NOPR, the Commission proposed to approve Reliability Standard BAL–006–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to BAL–006–1 that adds Measures and additional Levels of Non-Compliance including Measures concerning the accumulation of large inadvertent imbalances.[196]

424. In addition, the NOPR solicited comment on whether accumulation of large amounts of inadvertent imbalances is a concern to the industry and if so, options to address the accumulation.

i. Measures and Additional Levels of Non-Compliance Including Measures Concerning the Accumulation of Large Inadvertent Imbalances

(a) Comments

425. Certain commenters[197] do not support the Commission's proposal to add Measures and additional Levels of Non-Compliance, including Measures concerning the accumulation of large inadvertent imbalances. Xcel states that such a measure would not enhance reliability and involves primarily a commercial matter. MRO suggests that large inadvertent balances are an equity issue and as such should be addressed through business practices and not through the Reliability Standards. MidAmerican states that no additional measures addressing inadvertent imbalances are needed in this Reliability Standard because the issue is adequately addressed in other Reliability Standards.[198] MidAmerican states that if the Commission proceeds to require Measures and Levels of Non-Compliance for large accumulations, it must insure that no ''double penalties'' are imposed.

426. EEI believes that the need to set a Measure for the accumulation of large inadvertent imbalances may be premature. EEI suggests that inadvertent energy is not a problem in real-time operations and is the result of frequency over-bias. EEI further states that if the Commission believes the industry should address both inadvertent energy and frequency bias, the clear consequence is a fundamental reconsideration of the control performance standard. EEI strongly recommends that the Commission clarify whether it intends for the industry to reconsider this fundamental reliability principle.

427. Constellation states some concern regarding the ability of balancing authorities to make appropriate arrangements to settle inadvertent imbalances. In particular, Constellation states that in arranging bilateral paybacks, it is difficult to find a counterparty with an opposite balance and there are transmission fees that further hinder the process of these paybacks. Constellation states that the Commission should require the industry to adopt procedures that will better facilitate bilateral payback of inadvertent energy, such as waiving the

[194] *See* Applicability Issues: Bulk-Power Ststem v. Bulk Electric System and Applicability to Small Entities, *supra* sections II.C.1–2.

[195] *See* Common Issues Pertaining to Reliability Standards: Measures and Levels of Non-Compliance, *supra* section II.E.2.

[196] NOPR at P 212.

[197] Xcel, MRO, MidAmerican and MISO–PJM.

[198] MidAmerican explains that large interchange imbalances are a result of telemetry failures, AGC misoperation or scheduling errors and further states that BAL–001 addresses AGC performance and the INT standards handle compliance with scheduling requirements.

scheduling requirement for small bilateral paybacks (such as WECC has implemented).

428. TAPS repeats the arguments it made in its comments on the Staff Preliminary Assessment that the existing treatment of balancing authority inadvertent interchange is not comparable to the treatment of energy imbalances. TAPS suggests that the Commission has an obligation to do more than what is proposed in the NOPR, which states that the issue is being addressed in the OATT reform docket [199] while approving Reliability Standards that perpetuate the preferential treatment of balancing authority inadvertent interchange.[200]

(b) Commission Determination

429. The Commission directs the ERO to develop a modification to BAL–006–1 that adds Measures concerning the accumulation of large inadvertent imbalances and Levels of Non-Compliance. While we agree that inadvertent imbalances do not normally affect the real-time operations of the Bulk-Power System and pose no immediate threat to reliability, we are concerned that large imbalances represent dependence by some balancing authorities on their neighbors and are an indication of less than desirable balancing of generation with load. The Commission also notes that the stated purpose of this Reliability Standard is to define a process for monitoring balancing authorities to ensure that, over the long term, balancing authorities do not excessively depend on other balancing authorities in the Interconnection for meeting their demand or interchange obligations.

430. The Commission disagrees with MidAmerican that having Measures in this Reliability Standard will result in double penalties. The Commission believes that this Reliability Standard has an independent reliability goal that ''define[s] a process for monitoring balancing authorities to ensure that, over the long term, balancing authorities do not excessively depend on other balancing authority areas in the Interconnection for meeting their demand or interchange obligations.'' [201]

431. The Commission agrees with EEI that one of the root causes of inadvertent interchange is the difference between the actual frequency response and the existing bias settings. The Commission has directed that this cause be addressed in other BAL Reliability Standards. If the industry wishes to propose alternative metrics to the control performance Reliability Standards, the Commission suggests that it does so through the ERO processes and that such changes include an explanation of how the revised metrics would better measure the ability of an individual balancing authority to match load and generation.

432. In response to Constellation's comment about the fees associated with the settlement of inadvertent imbalances, the Commission notes that this issue relates to business practices and should be brought before NAESB or otherwise addressed in contexts other than section 215 of the FPA.

433. With respect to TAPS' concerns regarding disparate treatment of imbalances for non-control area utilities, the Commission is not convinced that this is a reliability issue. As identified in Order No. 890, inadvertent interchange is not comparable to imbalances.[202]

434. Accordingly, the Commission adopts the proposal in the NOPR to direct the ERO to develop Measures under this Reliability Standard to ensure balancing authorities will not have large inadvertent imbalances.

ii. Whether the Accumulation of Large Amounts of Inadvertent Imbalances Is a Concern and Potential Options

(a) Comments

435. LPPC states that its members are concerned that large inadvertent imbalances would be an indication of an underlying issue related to overall balancing of resources and demand and suggests that options to address these large inadvertent imbalances should be addressed through the Reliability Standards development process.

436. NERC states that the performance requirements that relate to reliability are addressed in BAL–001–0 and BAL–002–0 and the new Reliability Standards which will replace them. Further, NERC states that if the Commission wishes to direct consideration of limits on the amount of inadvertent imbalances, such directive should be in the form of an issue to be resolved or reliability objective to be achieved rather than a specific requirement to set a fixed limit on inadvertent accumulation.

437. TVA, MISO and MidAmerican state that the accumulation of large inadvertent balances over time does not raise grid reliability issues. TVA asserts that this is largely a financial matter. In addition, TVA comments that if a balancing authority inappropriately uses the interconnection in a way which results in a large inadvertent imbalance this behavior should be reflected in the balancing authority's control performance standard compliance. MISO states that some large amounts of inadvertent imbalance are due to a balancing authority fulfilling its bias obligation. MISO states that an arbitrary cap should not be a part of this Reliability Standard.

(b) Commission Determination

438. As stated previously, while the Commission agrees that these imbalances do not present an immediate reliability problem, we believe, as stated by LPPC, that large interchange imbalances are indicative of an underlying problem related to balancing of resources and demand. It would be worthwhile for the ERO to examine the WECC time error correction procedure.

439. Since the ERO indicates that the reliability aspects of this issue will be addressed in a Reliability Standards filing later this year, the Commission asks the ERO, when filing the new Reliability Standard, to explain how the new Reliability Standard satisfies the Commission's concerns.

iii. Summary of Commission Determinations

440. Accordingly, the Commission approves Reliability Standard BAL–006–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL–006–1 through the Reliability Standards development process that includes Measures concerning the accumulation of large inadvertent imbalances and additional Levels of Non-Compliance.

h. Regional Differences to BAL–006–1: Inadvertent Interchange Accounting and Financial Inadvertent Settlement

441. The NOPR explained that BAL–006–1 provides for two regional differences.[203] First, a regional difference is provided for an RTO with multiple balancing authorities. The control area participants of MISO requested that MISO be given an inadvertent interchange account so that financial settlement of all energy receipts and deliveries using locational marginal pricing could be implemented to meet their Commission directed market obligations. Subsequently, Southwest Power Pool (SPP) requested,

[199] OATT Reform NOPR at P 208.

[200] NOPR at P 206.

[201] *See* BAL–006–1 (Inadvertent Interchange, Purpose Statement).

[202] *See* Order No. 890 at P 702–03.

[203] NOPR at P 216.

and NERC approved, the same regional difference for.[204]

442. Second, the NOPR explained that a regional difference would apply to the control area participants of MISO and SPP that would allow each RTO to financially settle inadvertent energy between control areas in the RTO. Each RTO would maintain accumulations of the net inadvertent interchange for all the control areas in the RTO after the financial settlement, and therefore accumulation of net-interchange would not affect the non-participant control areas.

443. The Commission proposed to approve these regional differences, explaining that the two proposed regional differences relate solely to facilitating financial settlements of accumulated inadvertent interchange due to the physical differences of these areas and have minimal, if any, reliability implications.

i. Comments

444. FirstEnergy notes that the two proposed regional differences reference the Version 0 policies instead of the NERC Reliability Standards and requests that the Commission direct NERC to revise the regional differences accordingly. In addition, FirstEnergy states that the Commission should direct NERC to define the function of a waiver. FirstEnergy agrees that transferring responsibility for the tasks under these waivers to the RTO is appropriate.

ii. Commission Determination

445. No commenter objected to the regional differences to BAL–006–1. However, the Commission agrees with FirstEnergy that the regional differences incorrectly reference retired policy terminology. Therefore, the Commission approves the regional differences as mandatory and enforceable under Order No. 672 as necessary due to the physical differences between multiple balancing authorities and a single market [205] but the Commission directs the ERO to modify the regional differences so that they reference the current Reliability Standards and are in the standard form, which includes Requirements, Measures and Levels of Non-Compliance. The ERO should explore FirstEnergy's request to define the function of a waiver in its Reliability Standards development process.

[204] BAL–006–1, filed on August 28, 2006, would extend the regional difference to SPP.

[205] Order No. 672 at P 291.

2. CIP: Critical Infrastructure Protection

446. The goal of CIP–001–1 is to ensure that operating entities recognize sabotage events and inform appropriate authorities and each other to properly respond to the sabotage to minimize the impact on the Bulk-Power System.[206] The Reliability Standard requires that each reliability coordinator, balancing authority, transmission operator, generation operator and LSE have procedures for recognizing and for making operating personnel aware of sabotage events, and communicating information concerning sabotage events to appropriate ''parties'' in the Interconnection.[207]

447. In the NOPR, the Commission proposed to approve Reliability Standard CIP–001–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to CIP–001–0 that: (1) Includes Measures and Levels of Non-Compliance; (2) gives guidance for the term ''sabotage;'' (3) requires an applicable entity to contact appropriate federal authorities, such as the Department of Homeland Security, in the event of sabotage within a specified period of time and (4) requires periodic review of sabotage response procedures.

448. In the NOPR, the Commission explained that the Requirements of CIP–001–0 refer to a ''sabotage event'' but do not define that term. The Commission stated that, while ''sabotage'' is a commonly understood term and the common understanding should suffice in most circumstances, it was concerned that situations may arise in which it is not clear whether action pursuant to CIP–001–0 is required. Thus, the NOPR proposed that the ERO provide guidance clarifying the triggering event for an entity to take action pursuant to CIP–001–0.

a. Comments

449. EEI and Entergy comment that they generally agree with the Commission's perspective. While APPA and Six Cities support approving CIP–001–1 as mandatory and enforceable, they ask that the Commission defer the application of monetary penalties until further guidance is provided on what events are reportable and what steps an entity must take to be certain it is in compliance with the Reliability Standard. Claiming that CIP–001–1 is too vague to be enforceable, TAPS opposes approval until NERC has further defined ''sabotage'' and the facilities to which the Reliability Standard applies.

450. APPA questions whether CIP–001–1 should apply to LSEs (LSEs) contending that, unlike transmission owners and generators, LSEs do not own or operate ''hard assets'' that are normally thought of ''at risk'' to sabotage. It claims that compliance would be particularly burdensome for small LSEs, such as the requirement to provide a preliminary report within one hour of an event. APPA states that NERC should therefore reconsider whether LSEs should be required to comply with this Reliability Standard. Further, while APPA supports the application of CIP–001–1 to larger generators and any unit required for reliable interconnected operations, it questions whether it is critical to extend the Reliability Standard to all generator operators—noting that there are 3,564 generating plants in the United States with a total capacity of 75 MW or less. APPA contends that the incremental benefits of requiring all generators to comply with CIP procedures seem minimal since many facilities are unlikely to have a material impact on Bulk-Power System reliability or be a target for sabotage in the first place. APPA suggests that the Commission defer action on CIP–001–1 while it implements a prioritization plan.

451. TAPS and California Cogeneration are also concerned about applicability and contend that compliance should be limited to those that have a significant or material impact on Bulk-Power System reliability. Both are concerned that compliance with this Reliability Standard would create significant administrative burdens and documentation requirements that are not justified where a facility does not have a material impact on the Bulk-Power System. California Cogeneration suggests that CIP–001–1 be revised to: (1) Exclude generator output used on-site and (2) provide a mechanism for determining that a facility has no material impact and thus is exempt from compliance.

452. A number of commenters agree with the Commission's concern that the term ''sabotage'' needs to be better defined and guidance provided on the triggering events that would cause an

[206] The NOPR addressed CIP–001–0. On November 15, 2006, NERC submitted for approval proposed Reliability Standard CIP–001–1, which revised and replaced the previous version of the Reliability Standard to include Measures and Levels of Non-Compliance.

[207] On August 28, 2006, NERC submitted for approval proposed Reliability Standards CIP–002–1 through CIP–009–1. These proposed Reliability Standards, which relate to cybersecurity, are being addressed in a separate rulemaking proceeding in Docket No. RM06–22–000.

entity to report an event.[208] FirstEnergy states that this definition should differentiate between cyber and physical sabotage and should exclude unintentional operator error. It advocates a threshold of materiality to exclude acts that do not threaten to reduce the ability to provide service or compromise safety and security. SoCal Edison states that clarification regarding the meaning of sabotage and the triggering event for reporting would be helpful and prevent over-reporting.

453. APPA comments that Requirement R1 of CIP–001–1, which provides that an entity must have procedures for recognizing sabotage events and making its personnel aware of sabotage events, while a ''good first step,'' lacks sufficient detail upon which the ERO can base compliance and enforcement efforts. It characterizes CIP–001–1 as an ''entity-specific 'fill-in-the-blank' standard'' that does not provide sufficient direction or guidance for an entity to determine whether it is in compliance. APPA further states that Measure M1 provides no criteria for a Regional Entity, acting in its capacity as a compliance monitor, to make an objective determination that an entity's sabotage procedure is adequate.

454. In response to the Commission's concern regarding the need for periodic review of sabotage response procedures, FirstEnergy suggests that CIP–001–1 should define what time period is sufficient for periodic reviews and suggests that a bi-annual review would be appropriate. MRO believes that a requirement to annually review the sabotage response procedures should be added to the Reliability Standard.

455. NERC objects to the wording of the Commission's proposed directive that NERC modify CIP–001–1 to require an applicable entity to contact appropriate federal authorities, such as the Department of Homeland Security, in the event of sabotage within a specified period of time. NERC states the Commission's directive is overly prescriptive because it specifies language to be included in the standard and thereby circumvents the Reliability Standards development process. Further, NERC objects that this directive would require entities in other nations such as Canada or Mexico to report to the U.S. Department of Homeland Security. Santa Clara suggests that Requirement R4 (and corresponding measure M3) should be modified to state that ''* * * contacts should be established with the appropriate public safety officials or directly with the local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) such that communication channels are established to report incidents to the appropriate authority.'' It states that, in the case of a municipal utility that is part of a local governmental agency that already has a public safety department which is in regular contact with the local FBI, and where clear communication channels already exist between the public safety department and the utility, it would be redundant for the utility to establish a direct link to the FBI for reporting purposes. Xcel also suggests that the term ''appropriate federal authorities'' should be modified to avoid conflict with established processes now in place, and that the term should be specifically identified so the Requirements on affected entities are clear.

456. Process Electricity Committee advocates approval of CIP–001–0 as initially proposed by NERC without modification, but it objects to the revised CIP–001–1 as placing an undue burden on smaller entities. It is concerned that the Commission's proposal to require mandatory reporting to appropriate federal authorities within a specific time frame will impose substantial burdens on end users with little or no discernable benefit. It states that there is no evidence that any entities—both regulated and unregulated—under-report sabotage events. Further, according to Process Electricity Committee, the adoption of uniform requirements could require end users to modify existing security programs and procedures that are designed to protect industrial facilities, whereas the utility generator requirements could be conflicting or duplicative.

457. Entergy and FirstEnergy express concern that there is a potential for redundancy between CIP–001–1 and other related federal reporting standards. Entergy states that NERC should consider ensuring that CIP–001–1 is consistent with, but not duplicative of, these other requirements. FirstEnergy states that both the Department of Energy (DOE) and the Energy Information Administration (EIA) impose reporting requirements that are similar to CIP–001–1 and suggests that to avoid conflicts the reporting requirements under this Reliability Standard should be conformed to the existing DOE and EIA requirements. It also states that nuclear units have their own set of operating requirements, including procedures for reporting sabotage, and suggests that a company's compliance with NRC procedures should be presumed to meet NERC standards. EEI, FirstEnergy and Xcel suggest greater coordination, possibly with all events being reported to NERC, which would then coordinate with federal authorities. Xcel suggests the development of a single sabotage reporting form to streamline the reporting process and make it easier for affected entities to provide reports in a timely manner.

458. APPA and FirstEnergy express concern about a requirement to report an act of sabotage within a fixed period of time. Xcel states that the triggering event for disclosure of an act of sabotage often will be unclear and that an investigation will take time especially if the event occurs at an unstaffed or remote facility. Thus, Xcel does not believe that the standard should contain an express time limit for reporting an act of sabotage since the amount of time necessary to make that report may vary depending on the circumstances. FirstEnergy suggests that CIP–001–1 should define the specified period for reporting an incident beginning from when the event is discovered or suspected to be sabotage. APPA is also concerned that a specific time limit for a report (such as a 60 minute requirement) would be burdensome to meet for a small LSE that is not continuously staffed when a triggering event occurs outside staffed hours.

b. Commission Determination

i. Applicability to Small Entities

459. The Commission acknowledges the concerns of the commenters about the applicability of CIP–001–1 to small entities and has addressed the concerns of small entities generally earlier in this Final Rule. Our approval of the ERO Compliance Registry criteria to determine which users, owners and operators are responsible for compliance addresses the concerns of APPA and others.

460. However, the Commission believes that there are specific reasons for applying this Reliability Standard to such entities, as discussed in the NOPR. APPA indicates that some small LSEs do not own or operate ''hard assets'' that are normally thought of as ''at risk'' to sabotage. The Commission is concerned that, an adversary might determine that a small LSE is the appropriate target when the adversary aims at a particular population or facility. Or an adversary may target a small user, owner or operator because it may have similar equipment or protections as a larger facility, that is, the adversary may use an attack against a smaller facility as a training ''exercise.'' The knowledge of sabotage events that occur at any facility

[208] *See, e.g.,* APPA, FirstEnergy, SoCal Edison, Six Cities and TAPS.

(including small facilities) may be helpful to those facilities that are traditionally considered to be the primary targets of adversaries as well as to all members of the electric sector, the law enforcement community and other critical infrastructures.

461. For these reasons, the Commission remains concerned that a wider application of CIP–001–1 may be appropriate for Bulk-Power System reliability. Balancing these concerns with our earlier discussion of the applicability of Reliability Standards to smaller entities, we will not direct the ERO to make any specific modification to CIP–001–1 to address applicability. However, we direct the ERO, as part of its Work Plan, to consider in the Reliability Standards development process, possible revisions to CIP–001–1 that address our concerns regarding the need for wider application of the Reliability Standard. Further, when addressing such applicability issues, the ERO should consider whether separate, less burdensome requirements for smaller entities may be appropriate to address these concerns.

ii. Definition of Sabotage

462. Several commenters agree with the Commission's concern that the term ''sabotage'' should be defined. For the reasons stated in the NOPR, we direct that the ERO further define the term and provide guidance on triggering events that would cause an entity to report an event.[209] However, we disagree with those commenters that suggest the term ''sabotage'' is so vague as to justify a delay in approval or the application of monetary penalties. As explained in the NOPR, we believe that the term sabotage is commonly understood and that common understanding should suffice in most instances.[210] Further, in the interim while the matter is being addressed by the Reliability Standards development process, we direct the ERO to provide advice to entities that have concerns about the reporting of particular circumstances as they arise.

463. Further, in defining sabotage, the ERO should consider FirstEnergy's suggestions to differentiate between cyber and physical sabotage and develop a threshold of materiality. However, regarding the latter suggestion, the Commission directs that guidance for a threshold of materiality must be designed carefully to mitigate the risk that an unsuccessful sabotage event is not correctly reported because it did not cause sufficient harm.

iii. Procedures for Recognizing Sabotage Events

464. Requirement R1 of CIP–001–1 provides that an applicable entity must have procedures ''for the recognition of and for making their operational personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.'' The NOPR expressed concern that the provision does not establish baseline requirements regarding what issues should be addressed by the developed procedures. APPA goes even further and, characterizing it as an entity specific fill-in-the-blank standard, contends that it lacks sufficient detail upon which the ERO can base compliance and enforcement efforts.

465. While the Commission believes that this Reliability Standard can and should be enhanced by specifying baseline requirements regarding what issues should be addressed in the procedures for recognizing sabotage events and making personnel aware of such events, it disagrees with APPA that Requirement R1 lacks sufficient detail on which to base ERO compliance and enforcement efforts. As indicated in Measure M1, an applicable entity must have and maintain the procedure as defined by Requirement R1. Thus, if an applicable entity cannot provide the required procedure to the ERO or a Regional Entity auditor upon request, it would likely be subject to an enforcement action. While we expect that an applicable entity that has made a good faith effort to develop a meaningful procedure to comply with Requirement R1 (and Measure M1) would not be subject to an enforcement action, an ERO or Regional Entity audit team may provide steps to improve the individual entity's procedure, which would serve as a baseline for that entity for any subsequent audit. Such an approach would be acceptable and allow for meaningful compliance in the interim until CIP–001–1 is modified pursuant to our directive.

iv. Periodic Review of Sabotage Reporting Plans

466. The Commission was concerned that CIP–001–1 did not include a requirement for the periodic review or updating of sabotage reporting plans or procedures, or for the periodic testing of the sabotage reporting procedures to verify that they achieve the desired result.[211] In response, FirstEnergy suggests that a bi-annual review would be appropriate and MRO believes that an annual review requirement should be added to the Reliability Standard. Periodic testing of the procedures through an exercise would assist in determining if the procedures are adequate for achieving the desired result. Lessons learned from these events would help in developing or modifying the sabotage reporting procedures.

467. The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures. At this time, the Commission does not specify a review period as suggested by FirstEnergy and MRO and, rather, believes that the appropriate period should be determined through the ERO's Reliability Standards development process. However, the Commission directs that the ERO begin this process by considering a staggered schedule of annual testing of the procedures with modifications made when warranted formal review of the procedures every two or three years.

v. Mandatory Reporting of a Sabotage Event

468. CIP–001–1, Requirement R4, requires that each applicable entity establish communications contacts, as applicable, with the local FBI or Royal Canadian Mounted Police officials and develop reporting procedures as appropriate to its circumstances. The Commission in the NOPR expressed concern that the Reliability Standard does not require an applicable entity to actually contact the appropriate governmental or regulatory body in the event of sabotage. Therefore, the Commission proposed that NERC modify the Reliability Standard to require an applicable entity to ''contact appropriate federal authorities, such as the Department of Homeland Security, in the event of sabotage within a specified period of time.'' [212]

469. As mentioned above, NERC and others object to the wording of the proposed directive as overly prescriptive and note that the reference to ''appropriate federal authorities'' fails to recognize the international application of the Reliability Standard. The example of the Department of Homeland Security as an ''appropriate federal authority'' was not intended to be an exclusive designation. Nonetheless, the Commission agrees that a reference to ''federal authorities''

[209] *See* NOPR at P 224.

[210] *Id.* at P 224, n.140, quoting a dictionary definition of ''sabotage'' as ''destruction of property or obstruction of normal operations, as by civilians or enemy agents. * * *''

[211] NOPR at P 228.

[212] *Id.* at P 231.

could create confusion. Accordingly, we modify the direction in the NOPR and now direct the ERO to address our underlying concern regarding mandatory reporting of a sabotage event. The ERO's Reliability Standards development process should develop the language to implement this directive.

470. As noted above, FirstEnergy, EEI and others express concern regarding the potential for redundant reporting under CIP–001–1 and other government reporting standards, and the need for greater coordination. The Commission understands the concern about multiple reporting channels that may arise and the burden that this may present to applicable entities. We direct the ERO to explore ways to address these concerns—including central coordination of sabotage reports and a uniform reporting format—in developing modifications to the Reliability Standard with the appropriate governmental agencies that have levied the reporting requirements.

471. The Commission stated that the reporting of a sabotage event should occur within a fixed period of time, and referred to a Homeland Security procedure that references a 60-minute period for submitting a preliminary report and a follow-up report within four to six hours.[213] While commenters raise a number of concerns about the need for fairness in the implementation of such a requirement, they do not challenge the NOPR's underlying concern or the appropriateness of such a provision. The Commission believes that an applicable entity should report a sabotage event in a timely manner to allow government authorities and critical infrastructure members the opportunity to react in a meaningful manner to such information. Thus, the Commission directs the ERO to modify CIP–001–1 to require an applicable entity to contact appropriate governmental authorities in the event of sabotage within a specified period of time, even if it is a preliminary report. The ERO, through its Reliability Standards development process, is directed to determine the proper reporting period. In doing so, the ERO should consider suggestions raised by commenters such as FirstEnergy and Xcel to define the specified period for reporting an incident beginning from when an event is discovered or suspected to be sabotage, and APPA's concerns regarding events at unstaffed or remote facilities, and triggering events occurring outside staffed hours at small entities.

c. Summary of Commission Determinations

472. As explained in the NOPR, while the Commission has identified concerns regarding CIP–001–1, we believe that the proposal serves an important purpose in ensuring that operating entities properly respond to sabotage events to minimize the adverse impact on the Bulk-Power System. Accordingly, the Commission approves Reliability Standard CIP–001–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) Further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event; (2) specify baseline requirements regarding what issues should be addressed in the procedures for recognizing sabotage events and making personnel aware of such events; (3) incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures and (4) require an applicable entity to contact appropriate governmental authorities in the event of sabotage within a specified period of time. In addition, we direct the ERO, as part of its Work Plan, to consider revisions to CIP–001–1 that address our concerns regarding applicability to smaller entities. The ERO should also consider consolidation of the sabotage reporting forms and the sabotage reporting channels with the appropriate governmental authorities to minimize the impact of these reporting requirements on all entities.

3. COM: Communications

473. The Communications (COM) group contains two Reliability Standards. The first requires that transmission operators, balancing authorities and other applicable entities have adequate internal and external telecommunications facilities for the exchange of interconnection and operating information necessary to maintain reliability. The second Reliability Standard requires that these communication facilities be staffed and available to address real-time emergencies and that operating personnel carry out effective communications.

474. The NOPR contained a discussion of how the transmission operator and generator operator function would apply to RTO, ISO and pooled resource organizations. In this Final Rule, conclusions concerning those issues are covered in the Applicability Issues section.[214] In essence, an organization may, but does not have to, accept compliance responsibility on behalf of its members. Since telecommunication is vital to the Reliable Operation of the Bulk-Power System, the Commission finds that it is not permissible to have either unnecessary overlaps or gaps in telecommunications.

a. Telecommunications (COM–001–1)

475. COM–001–0 [215] seeks to ensure coordinated telecommunications among operating entities, which are fundamental to maintaining grid reliability. This proposed Reliability Standard establishes general telecommunications requirements for specific operating entities, including equipment testing and coordination. It also establishes English as the common language between and among operating personnel, and sets policy for using the NERCNet telecommunications system. COM–001–0 applies to transmission operators, balancing authorities, reliability coordinators and NERCNet user organizations.

476. The Commission proposed to approve Reliability Standard COM–001–0 as mandatory and enforceable. In addition, the Commission proposed to direct that NERC submit a modification to COM–001–0 that: (1) Includes Measures and Levels of Non-Compliance; (2) includes generator operators and distribution providers as applicable entities and (3) includes Requirements for communication facilities for use during emergency situations.

477. In addition, the Commission sought comments on specific requirements or performance criteria for telecommunications facilities, noting that COM–001–0 might be improved by providing specific requirements for adequacy, redundancy, diverse routing, and periodic testing. The Commission also sought comments on whether the relative roles of applicable entities should be considered when setting down requirements for telecommunication facilities, since the needs will vary based on role.

[213] *Id.* at n.142.

[214] *See* Applicability Issues: Use of the NERC Functional Model, *supra* section II.C.4.

[215] In its November 15, 2006, filing, NERC submitted COM–001–1, which supercedes the Version 0 Reliability Standard. COM–001–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, COM–001–1.

478. Most comments address the specific modifications and concerns raised by the Commission in the NOPR. Below, we address each topic separately, followed by a summary of our conclusions.

i. Applicability to Generator Operators and Distribution Providers and their Telecommunications Facility Requirements

479. The Commission stated in the NOPR that communications with generator operators and distribution providers are necessary to maintain system reliability during normal and emergency situations, while recognizing that telecommunication facility needs will vary between these two entities and other reliability entities such as reliability coordinators, transmission operators and balancing authorities. The Requirements for each of these entities will vary according to its respective roles.

(a) Comments

480. EEI supports the goals stated by the Commission with regard to COM–001–1, in particular, the need to apply this Reliability Standard to distribution providers. TVA agrees with the Commission's reasoning that generator operators and distribution providers should be subject to this Reliability Standard, but seeks clarification that such entities may transfer their responsibility for data sharing with and reporting to NERC and Regional Entities by contract to another entity.

481. In contrast, MRO, APPA, TAPS and SDG&E indicate that applying this Reliability Standard to generator operators and distribution providers may not be appropriate. APPA argues generator operators and distribution providers do not affect the Bulk-Power System in the same manner as a reliability coordinator, balancing authority or transmission provider does, since generator operators and distribution providers only have a secondary or support role with respect to reliability of the Bulk-Power System.

482. Further, APPA and SDG&E are concerned that the Commission's proposal would unnecessarily subject generator operators and distribution providers to Requirements that were designed for transmission operators. For example, APPA indicates that NERCNet was designed as part of the NERC Interregional Security Network for communications among reliability coordinators, balancing authorities and transmission operators, and was not designed to connect generators to their balancing authorities and distribution providers to their transmission operators. Further, SDG&E submits that, while generator operators and distribution providers may logically have some role in enabling communications that help ensure reliability, SDG&E sees no basis for subjecting such entities to the same, extensive requirements incumbent on transmission operators.

483. APPA argues that, while telecommunications Reliability Standards with generator operators and distribution providers as applicable entities may be needed, they are already subject to telecommunications requirements as part of their bilateral interconnection agreements with balancing authorities and transmission providers. It contends that if NERC deems it necessary, a separate Reliability Standard should be developed to govern telecommunications between balancing authorities and generator operators, and between transmission operators and distribution providers under their respective footprints.

484. TAPS states that Requirement R1.4 has an ambiguous requirement [216] that, if applied to distribution providers and generator operators, would impose redundancy requirements well beyond what is reasonably necessary for Bulk-Power System reliability. Further it asserts that the NOPR provides no basis for expanding the Reliability Standard to small entities, such as a 2–MW distribution provider or generator, much less than one that has no connection to the bulk transmission system. Finally, TAPS contends that, in making this proposal, the Commission is ''over-stepping its bounds'' by not leaving it to the ERO's expert judgment whether COM–001–1 has sufficient coverage to protect Bulk-Power System reliability and states that, in any event, applicability should be limited through NERC's registry criteria and definition of bulk electric system.

485. MRO further states that applying this Reliability Standard to generator operators and distribution providers and including Requirements for communication facilities for use during emergency situations may also not be appropriate if the distribution provider does not operate its own systems.

486. California PUC believes that the Commission's assertion of authority to impose Reliability Standards applicable to either generator operators or distribution providers should be extremely limited, and should be based on an essential nexus between the proposed Reliability Standard and the operation of the Bulk-Power System. It contends that this aspect of the Commission's proposed directive is duplicative and unnecessary when applied to entities in California, and risks being counterproductive unless applied with considerable restraint since California PUC's Operation Standards require power plants to maintain the ability to communicate with the balancing authority at all times, and to plan for the continuity of communications during emergencies.

487. Process Electricity Committee agrees that the extent and maintenance of telecommunication facilities should vary based on the operator's potential affect on system reliability. It points out that existing regulations and contractual obligations already require end users to maintain adequate communications facilities. Further, it states that on-site generation interconnected with the electricity grid typically is required to maintain sufficient telecommunications facilities between the generator owner or operator and the grid operator. In the absence of evidence that this arrangement is inadequate, Process Electricity Committee recommends that the amended COM Reliability Standards be clarified so that they do not impose new requirements on end users and other entities that have only minimal impact on the reliability of the interconnected transmission network.

(b) Commission Determination

488. The Commission reaffirms its position that generator operators and distribution providers should be included as applicable entities in COM–001–1 to ensure there is no reliability gap during normal and emergency operations. For example, during a blackstart when normal communications may be disrupted, it is essential that the transmission operator, balancing authority and reliability coordinator maintain communications with their distribution providers and generator operators. However, the current version of Reliability Standard COM–001–1 does not require this because it does not include generator operators and distribution providers as applicable entities. We clarify that the NOPR did not propose to require redundancy on generator operators' or distribution providers' telecommunication facilities or that generator operators or distribution providers be trained on anything not related to their functions during normal and emergency conditions. We expect the telecommunication requirements for all applicable entities will vary according to their roles and that these

[216] COM–001–1 Requirement R1.4 states: ''Where applicable, these [telecommunications] facilities shall be redundant and diversely routed.''

requirements will be developed under the Reliability Standards development process.

489. As stated in the Applicability Issues section of this Final Rule, entities may share responsibility for complying with Reliability Standards and the ERO's registration process takes this into account.[217] We believe that this satisfies TVA's concern about data sharing and reporting responsibilities and MRO's concern about applying this Reliability Standard to distribution providers only if they operate their own systems.

490. The Commission agrees with APPA that the primary purpose of Requirement R6 is to provide information to ensure reliable interregional operations and therefore should not apply to generator operators and distribution providers. However, we disagree that this leads to the conclusion that generator operators and distribution providers should not be included in COM–001–1. As we have stated, telecommunication requirements for all applicable entities will vary according to their roles. In modifying COM–001–1 through the Reliability Standards development process, the Commission believes that the ERO should create appropriate telecommunications requirements for generator operators and distribution providers, which may be additional and separate Requirements to COM–001–1 or, alternatively, a new Reliability Standard as suggested by APPA.

491. In response to SDG&E, the Commission's intent is not to subject generator operators and distribution providers to the same requirements placed on transmission operators. As part of the modification of this Reliability Standard or development of a new Reliability Standard to include the appropriate telecommunications facility requirements for generator operators and distribution providers, the ERO should take into account what would be required of generator operators and distribution providers in terms of telecommunications for the Reliable Operation of the Bulk-Power System, instead of applying the same requirements as are placed on other reliability entities such as reliability coordinators, balancing authorities and transmission operators.

492. With regard to TAPS's comment, the Commission has identified a concern and directs that the ERO address the matter through its Reliability Standards development process. This comports with section 215(d)(5) of the FPA which authorizes the Commission, upon its own motion, to order the ERO ''to submit to the Commission a proposed Reliability Standard or a modification to a Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Reliability Standard appropriate to carry out this section.'' We have identified such a matter and have left to the ERO to develop a specific proposal by invoking its Reliability Standards development process. Further, consistent with our discussion above regarding applicability of Reliability Standards, applicability would be limited through NERC's registry criteria and definition of bulk electric system at this time.

493. In response to California PUC, in this Final Rule we are initially limiting the applicability of these Reliability Standards to those users, owners and operators of the Bulk-Power System on the ERO's compliance registry. The Commission notes that it has jurisdiction under section 215 of the FPA over all users, owners and operators of the Bulk-Power System to ensure Reliable Operation of the Bulk-Power System. To ensure reliability, it is important to include appropriate generator operators and distribution providers as applicable entities in Reliability Standard COM–001–1. However, any generator operator or distribution provider that is not a user, owner or operator of the Bulk-Power System will not be included. Also, at this time, the Bulk-Power System is defined on the basis of the ERO's definition of the ''bulk electric system.'' The Commission believes that this should satisfy California PUC's concern that this Reliability Standard be limited to Bulk-Power System operations. We will not further limit our directive as to which entities this Reliability Standard should apply.

494. As we explained in the NOPR, communication with generator operators and distribution providers becomes especially important during an emergency when generators with black start capability must be placed in service and nearby loads restored as an initial step in system restoration. This occurs at a critical time when normal communication paths may be disrupted. While many generator operators and distribution providers may have telecommunications requirements pursuant to a bilateral contract as indicated by APPA, it is important that all generator operators and distribution providers identified by the ERO through its registration process are subject to uniform telecommunications requirements. Therefore, we adopt our proposal to require the ERO to modify COM–001–1 to apply to generator operators and distribution providers. However, we recognize that some of the existing requirements (such as Requirement R6 related to NERCNet) need not apply to generator operators and distribution providers. In light of commenters' concerns, as an alternative, it would be acceptable for the ERO to develop a new Reliability Standard that would specifically address an appropriate range of Requirements for telecommunication facilities of generator operators and distribution providers that reflect their respective roles on Reliable Operation of the Bulk-Power System.

ii. Requirements for Telecommunications Facilities

495. The Commission sought comment on specific requirements or performance criteria for telecommunication facilities and whether the modified Reliability Standard should provide requirements that also consider the relative role of applicable entities.

(a) Comments

496. A number of commenters agree with the Commission that the relative role of an entity should be taken into account when specifying the requirements for its telecommunications facilities.[218] For example, ISO–NE states that a single generator operator will not need the level of redundancy and diverse routing that a reliability coordinator needs.

497. Many commenters recommend that telecommunications facilities requirements should be specified in broad terms. EEI, APPA, Alcoa, International Transmission, LPPC and SoCal Edison believe that revision to COM–001–1 should provide specific or minimum requirements for adequacy, redundancy and diverse routing. However, EEI, Alcoa and Northern Indiana maintain that entities should have flexibility in meeting the requirements and to allow for innovative technological advancements. Alcoa and Northern Indiana maintain that without flexibility, an applicable entity may choose a less optimal solution just to comply with the Reliability Standard. EEI asserts that such flexibility will also permit alternative means of implementing the requirements that will translate into cost savings. International Transmission

[217] *See* Applicability Issues: Applicability to Small Entities, *supra* section II.C.2.

[218] *See*, *e.g.*, EEI, International Transmission, ISO–NE, Process Electricity Committee and SoCal Edison.

cautions that we should not prejudice the modification of this Reliability Standard by indicating the specific requirements or the performance criteria.

498. APPA states that, because the communications requirements for an entity that is responsible for serving 3,000 MW of load is distinctly different from another entity that serves 30 MW of load, the ERO should take the size of the entity into consideration.

499. NERC believes that the questions posed by the NOPR regarding performance criteria should be considered through the Reliability Standards development process, in accordance with NERC's Work Plan, which will allow a broader industry debate on the requirements for telecommunications facilities. This approach will avoid any potential conflicts with the requirements already established in the telecommunications industry and by the Institute of Electrical and Electronics Engineers.

500. Entergy states that it is unclear what cyber assets are covered by COM–001–0. Entergy believes that the Reliability Standard should focus on telecommunications that support the operation of critical assets. Entergy also believes that COM–001–0 should be expanded to include advances in communications technology. It states that NERC should consider addressing the following in a way that will facilitate an understanding of the Reliability Standards' requirements: (1) Voice communications; (2) command and control data communications; (3) security coordination data communications; (4) digital messaging communications; (5) human linguistic convention and (6) other types of communications, including video conferencing and communications with remote security cameras. Entergy believes that this could be accomplished through an enhancement to the definition of communications in the NERC glossary and recasting COM–001–0 to improve the specificity of requirements for each form of communication. Finally, Entergy believes that Requirement R4 of COM–001–0, which requires reliability coordinators, transmission operators and balancing authorities to use English in all types of communications, should apply only to verbal and written communications.

501. FirstEnergy asserts that the Requirement R2 is unclear because it does not specify whether the phrase ''telecommunication facilities'' covers both voice and data facilities in the context of alarms. It states that, although the word ''telecommunications facilities'' is generally understood to mean both voice and data facilities, the current practice is to display alarms only for data facilities. Requirement R2 could be misinterpreted to require alarms on voice facilities as well, which would be impractical.

502. Six Cities is concerned that the scope of improper conduct under the ''NERCNet security policy'' in Attachment 1 is virtually limitless [219] Six Cities recognizes that it would be difficult to provide a comprehensive and detailed list of all conduct that might be considered a misuse of NERCNet data, but that difficulty does not justify exposing NERCNet users to the risk of monetary penalties based on amorphous and unbounded descriptions of potentially violative conduct. Six Cities states that one solution would be to limit the imposition of monetary penalties for misuse of NERCNet data to instances where such misuse is intentional or grossly negligent. According to Six Cities, it would be appropriate to exact a monetary penalty where a NERCNet user deliberately uses NERCNet data for unauthorized or unreasonable purposes. Six Cities asks that it be modified to provide for a warning for the improper disclosure of NERCNet data where the disclosure was not intentional or grossly negligent.

(b) Commission Determination

503. The Commission adopts its NOPR proposal that telecommunications facility requirements must reflect the roles of the respective operating or reliability entities that are included in the applicability section in this Reliability Standard and how they would affect the reliability of the Bulk-Power System. We note that most commenters agree with this approach.

504. The Commission agrees with commenters that flexibility is important in setting telecommunications requirements in order to foster innovation, allow the adoption of new technologies and provide for cost-effective solutions for compliance with the Reliability Standard. However, the Commission finds that certain modifications to COM–001–1 are necessary to ensure system reliability. We believe that the ERO must specify requirements for using telecommunications facilities during normal and emergency conditions that: (1) Reflect the roles of the applicable entities and their impact on Reliable Operation and (2) include adequate flexibility. Accordingly, the Commission directs the ERO to modify COM–001–1 through the Reliability Standards development process to address our concerns. The Commission believes that the concerns of Entergy and FirstEnergy are best addressed by the ERO in the Reliability Standards development process.

505. Six Cities suggests specific new improvements to COM–001–1. As stated above, such comments should be addressed as the ERO modifies the Reliability Standards in the Reliability Standards development process.

iii. Measures and Levels of Non-Compliance

506. In its November 15, 2006, filing, NERC submitted COM–001–1, which supersedes the Version 0 Reliability Standard. COM–001–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard.

(a) Comments

507. ISO–NE notes that Compliance 1.1 of COM–001–0 specifies that ''Regional Reliability Organizations shall be responsible for compliance monitoring * * *.'' ISO–NE suggests that since NERC designed and created NERCNet, NERC should be responsible for maintaining and ensuring the compliance with the Reliability Standard rather than regional reliability organizations. ISO–NE recommends that the Commission direct NERC to modify Compliance 1.1 to provide that NERC shall be responsible for monitoring compliance of the NERCNet user organizations.

(b) Commission Determination

508. With respect to ISO–NE's comment, we find that a regional reliability organization does not have any role with compliance matters; that role is reserved for the ERO or the Regional Entities. However, we disagree with ISO–NE that the ERO must replace the regional reliability organization as the compliance monitor. The fact that NERC designed and created NERCNet does not require the ERO to be the compliance monitor. Section 215 of the FPA states that the ERO may delegate compliance and enforcement authority to a Regional Entity, even if the ERO creates the Reliability Standards. Therefore, although we direct that the

[219] Attachment 1 provides that Violations of the NERCNet Security Policy shall include, but not be limited to any act that:

Exposes NERC or any user of the NERCNet to actual or potential monetary loss through the compromise of data security or damage.

Involves the disclosure of trade secrets, intellectual property, confidential information or the unauthorized use of data.

Involves the use of data for illicit purposes, which may include violation of any law, regulation or reporting requirement of any law enforcement or government body.

regional reliability organization should not be the compliance monitor for NERCNet, we leave it to the ERO to determine whether it is the appropriate compliance monitor or if compliance should be monitored by the Regional Entities for NERCNet User Organizations.

iv. Summary of Commission Determination

509. While the Commission has identified a number of concerns with regard to COM–001–1, this Reliability Standard is independently enforceable without the modifications we are directing. Therefore, the Commission approves Reliability Standard COM–001–1 as mandatory and enforceable. Because of the importance of this Reliability Standard in requiring transmission operators and others to have necessary telecommunications equipment, we additionally, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, direct the ERO to develop a modification to COM–001–1 through the Reliability Standards development process that: (1) Expands the applicability to include generator operators and distribution providers and includes Requirements for their telecommunications facilities; (2) identifies specific requirements for telecommunications facilities for use in normal and emergency conditions that reflect the roles of the applicable entities and their impact on Reliable Operation and (3) includes adequate flexibility for compliance with the Reliability Standard, adoption of new technologies and cost-effective solutions. As an alternative to applying this Reliability Standard to generator operators and distribution providers, the ERO may develop a new Reliability Standard that will address the Requirements for telecommunication facilities applicable to generator operators and distribution providers.

b. Communications and Coordination (COM–002–2)

510. COM–002–2 [220] seeks to ensure that transmission operators, generator operators and balancing authorities have adequate communications and that their communications capabilities are staffed and available to address real-time emergency conditions. This Reliability Standard requires balancing authorities and transmission operators to notify others through pre-determined communication paths of any condition that could threaten the reliability of their areas or when firm load shedding is anticipated.

511. The Commission proposed in the NOPR to approve Reliability Standard COM–002–1 as mandatory and enforceable. In addition, the Commission proposed to direct that NERC submit a modification to COM–002–1 that: (1) Includes Measures and Levels of Non-Compliance; (2) includes a Requirement for the reliability coordinator to assess and approve actions that have impacts beyond the area views of transmission operators or balancing authorities; (3) includes distribution providers as applicable entities and (4) requires tightened communications protocols, especially for communications during alerts and emergencies. With respect to this final issue, the Commission proposed alternatively to direct NERC to develop a new Reliability Standard that responds to Blackout Report Recommendation No. 26, which deals with the need for tightened communications protocols.

i. Applicability to Distribution Providers

(a) Comments

512. While EEI states that there is a clear need to apply the Reliability Standard to distribution providers, APPA finds the proposal problematic because it would mean that close to 2,000 public power systems would have to be added to the compliance registry. APPA argues that the Commission should instruct NERC to consider the applicability of COM–002–2 to distribution providers through its Reliability Standards development process. MRO requests that the Commission clarify whether the distribution providers will continue to operate their own systems in the future.

(b) Commission Determination

513. The Commission finds that, during both normal and emergency operations, it is essential that the transmission operator, balancing authority and reliability coordinator have communications with distribution providers. In response to APPA, as discussed above, any distribution provider that is not a user, owner or operator of the Bulk-Power System would not be required to comply with COM–002–2, even though the Commission is requiring the ERO to modify the Reliability Standard to include distribution providers as applicable entities. APPA's concern that 2,000 public power systems would have to be added to the compliance registry is misplaced, since, as we explain in our Applicability discussion above, we are approving NERC's registry process, including the registry criteria. Therefore, we adopt our proposal to require the ERO to modify COM–002–2 to apply to distribution providers through its Reliability Standards development process.

514. The Commission believes that this Reliability Standard does not alter who would operate a distribution provider's system. It only concerns communications, not the operation of the distribution system.

ii. Measures and Levels of Non-Compliance

(a) Comments

515. APPA notes that the Levels of Non-Compliance for COM–002–2 are inadequate in two respects: (1) reliability coordinators are not included in any Level of Non-Compliance and (2) the Levels of Non-Compliance for transmission operators and balancing authorities in Compliance D.2 do not reference Requirements R1 and R2. Therefore, APPA would support approval of COM–002–2 as a mandatory Reliability Standard, but would not support levying penalties for violating incomplete portions of the Reliability Standard.

(b) Commission Determination

516. As stated in the Common Issues section, a Reliability Standard is enforceable even if it does not contain Levels of Non-Compliance.[221] However, the Commission agrees with APPA that this Reliability Standard could be improved by incorporating the changes proposed by APPA. Therefore, when reviewing the Reliability Standard through the Reliability Standards development process, the ERO should consider APPA's concerns.

iii. Reliability Coordinator Assessment and Approval of Actions that have Impacts Beyond the Area Views of Transmission Operators and Balancing Authorities

(a) Comments

517. Alcoa argues that there is a need for communication regarding operating actions taken by transmission operators and balancing authorities that may have impacts beyond their area views. However, a number of commenters oppose the Commission's proposal to modify the Reliability Standard to require reliability coordinators to assess and approve actions that have impacts

[220] In its November 15, 2006, filing, NERC submitted COM–002–2, which supercedes the Version 1 Reliability Standard. COM–002–2 adds Measures and Levels of Non-Compliance to the Version 1 Reliability Standard. In this Final Rule, we review the November version, COM–002–2.

[221] *See* Common Issues Pertaining to Reliability Standards: Measures and Levels of Non-Compliance, *supra* section II.E.2.

beyond the area views of transmission operators or balancing authorities and seek clarifications.[222] Alcoa, California PUC, SDG&E and Xcel are concerned that obtaining approval from reliability coordinators could create delays in completing the operating action in emergency situations. Xcel and Alcoa request that the Commission clarify that this requirement would not prevent timely performance by a transmission operator of actions necessary to maintain the reliability of its system under emergency conditions.[223] Both Alcoa and Xcel are concerned that waiting for an assessment and approval by a reliability coordinator may not be feasible, especially during emergencies. Xcel further asks the Commission to clarify that the entity taking operating actions should not be held responsible for delays caused by the reliability coordinator's assessment and approval. Alcoa suggests that there should be a clear definition of what actions have an impact beyond the area views of transmission operators or balancing authorities. SDG&E further states that serious damage to transmission equipment could occur if the transmission operator is not able to take immediate action during an emergency.

518. ISO–NE is concerned that the Commission proposal goes too far and if implemented, will prevent capable transmission operators from quickly addressing reliability problems that may arise. It maintains that transmission operators usually do not have enough time to inform the reliability coordinator, who must then ''assess and approve'' the proposed action. If the Commission's proposal is implemented, transmission operators will doubt themselves and delay necessary action. However, it does not see any problem for the New England balancing area and the NPCC region, because ISO–NE serves as the New England reliability coordinator, balancing authority and transmission operator.

519. APPA contends that the Commission's proposed directive appears to have been covered under Reliability Standard IRO–005–1. EEI agrees, stating that IRO–005–1 already requires a reliability coordinator to ensure that transmission operators and balancing authorities operate to prevent action or non-action that will impact neighboring areas.[224]

(b) Commission Determination

520. The Commission reaffirms its belief that Reliable Operation of the Bulk-Power System can only be achieved by coordinated efforts of all operating entities, such as reliability coordinators, transmission operators and balancing authorities in operating their respective systems and performing their respective functions in accordance with their responsibilities and authorities. Most operating actions taken by transmission operators and balancing authorities in real-time would only affect their own areas and equipment and have no adverse impacts on the interconnection reliability operating limits, and therefore they have unilateral authority to act. However some operating actions that would have impacts beyond their own areas must involve the reliability coordinator who has the wide-area views and the necessary operating tools, including monitoring facilities and real-time analytic tools with wide-area representation to enable the reliability coordinator to fulfill its responsibility.[225] In response to Alcoa, the Commission believes that actions that have an impact beyond an area will, in general, vary based on the conditions at the time of the action.

521. Further, we clarify that we did not propose to require an entity to inform its reliability coordinator of every action it takes. Instead, the proposed directive included a Requirement for the reliability coordinator to assess and approve only those actions that have impacts beyond the area views of transmission operators and balancing authorities. We remain convinced that it is the reliability coordinator's responsibility to ensure Reliable Operation of its reliability coordinator area. The reliability coordinator must also ensure that actions taken by operating entities under its authority will not have wide-area impacts that would adversely impact Reliable Operation of the Bulk-Power System. Therefore, we adopt the proposed directive as stated in the NOPR.

522. In response to commenters, the Commission clarifies that the proposed directive does not conflict with the transmission operators' and balancing authorities' rights to take actions necessary to preserve reliability of their areas and alleviate operating emergencies, consistent with Requirement R1 and R2 in TOP–001–1.[226] Further, the proposed directive does not in any way diminish their operating authority regarding local area reliability for normal and emergency situations, a responsibility that is under the responsibility of a transmission operator or a balancing authority. However, the majority of their operating actions are not emergency actions and would only affect a transmission operator's or balancing authority's area of responsibilities. Since these actions are expected to have little impact outside of the transmission operator's or balancing authority's area, the authority to take unilateral actions remains with the transmission operator or balancing authority. Other non-emergency actions should be coordinated with the reliability coordinator prior to taking action.

523. Regarding SDG&E's concern that serious damage to transmission equipment could occur if the transmission operator is not able to take immediate action during an emergency, we believe this is adequately addressed under Requirement R3 of TOP–001–0 which provides that operating entities need not comply with directives from reliability coordinators when such actions would violate safety, equipment, regulatory or statutory requirements.

524. NERC should consider Xcel's suggestion that the entity taking operating actions should not be held responsible for delays caused by the reliability coordinator's assessment and approval in the Reliability Standards development process. We note that the operating entity has the authority to take emergency actions to protect its system that may circumvent or preempt the reliability coordinator's approval process under TOP–001–1 Requirement R3 in cases of personnel safety, potential equipment failure or environmental needs.

525. We disagree with commenters that the Commission's proposed

[222] *See, e.g.*, APPA, EEI, California PUC, ISO–NE and SDG&E.

[223] Alcoa notes that this is consistent with the Requirements in TOP–001–1, which provides transmission operators and balancing authorities wide latitude to preserve reliability of their area.

[224] The Requirement R13 of IRO–005–1 provides that ''[e]ach reliability coordinator shall ensure that Transmission Operators, Balancing Authorities * * * operate to prevent the likelihood that a disturbance, action or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection.''

[225] The NERC glossary states that A reliability coordinator is the ''entity that is the highest level of authority who is responsible for the reliable operation of the bulk electric system, has the wide-area view of the bulk electric system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The reliability coordinator has the purview that is broad enough to enable the calculation of IROLs, which may be based on the operating parameters of transmission systems beyond any transmission operator's vision.'' NERC Glossary at 15.

[226] TOP–001–1, R1 states in part ''Each transmission operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area * * * '' and R2 states in part ''Each transmission operator shall take immediate actions to alleviate operating emergencies * * *.''

directive is already covered under Requirement R13 of IRO–005–1, which requires each reliability coordinator to ensure that all transmission operators, balancing authorities and others operate to prevent the likelihood that a disturbance, action, or non-action in its reliability coordinator area will result in a SOL and IROL violation in another area of the Interconnection. In order for the reliability coordinator to carry out its function under IRO–005–1, it must have information from the transmission operators and balancing authorities. However, IRO–005–1 does not require transmission operators and balancing authorities to provide the reliability coordinator with the information it would need to prevent the likelihood that an action from these two entities will result in a SOL or IROL violation in another area of the Interconnection. The Commission's directive ensures that the reliability coordinator has such information. Therefore, we do not believe that COM–002–2 is duplicative of IRO–005–1.

526. Accordingly, we direct the ERO to include a Requirement for the reliability coordinator to assess and approve actions that have impacts beyond the area views of transmission operators or balancing authorities, including how to determine whether an action needs to be assessed by the reliability coordinator. This Requirement is best developed under the Reliability Standards development process including the consideration whether this Requirement should be included in this communications Reliability Standard or an operating Reliability Standard.

iv. Tightened Communications Protocols

527. The Blackout Report cited ineffective communications as a factor common to the August 14, 2003 blackout and other previous major outages in North America.[227] In addition, Recommendation No. 26 of the Blackout Report instructed NERC, working with reliability coordinators and control area operators, to ''[t]ighten communications protocols, especially for communications during alerts and emergencies * * * ''.[228] In the NOPR, the Commission endorsed Blackout Recommendation No. 26 and proposed to direct the ERO to require tightened communications protocols, especially for communications during alerts and emergencies. Alternatively, we proposed to direct the ERO to develop a new Reliability Standard that responds to the Blackout Report Recommendation.

(a) Comments

528. In its response to the Staff Preliminary Assessment, NERC agreed with the need to develop additional Reliability Standards addressing consistent communications protocols among personnel responsible for the reliability of the Bulk-Power System.[229]

529. EEI supports the Commission in its concerns regarding Blackout Recommendation No. 26 on emergency communications. However, EEI states that Requirement R4 of EOP–001–0, Emergency Operations Planning, addresses the Commission's concerns about communication protocols during emergency conditions.[230] EEI recommends that, instead of duplicating the same requirement in COM–002–2, the Commission should consider directing NERC to provide an interpretation on the elements of such protocols.

530. APPA believes that the communications protocols to be used during emergencies should be included in the relevant Reliability Standard that governs each type of emergency, rather than in COM–002–2. For example, Requirement R3 of Reliability Standard VAR–002–1 establishes the protocol for communication with the transmission operator if a generator loses its ability to provide voltage control. By keeping the necessary communication protocols clustered with the events to which they apply, NERC would make the Reliability Standards more user-friendly.

531. MISO claims that Blackout Report Recommendation No. 26 on tightened communications protocols dealt primarily with NERC infrastructure and has been fully implemented. It is concerned that developing measures that require ongoing administration will impede rather than improve timely communications in an emergency.

(b) Commission Determination

532. We adopt our proposal to require the ERO to establish tightened communication protocols, especially for communications during alerts and emergencies, either as part of COM–002–2 or as a new Reliability Standard. We note that the ERO's response to the Staff Preliminary Assessment supports the need to develop additional Reliability Standards addressing consistent communications protocols among personnel responsible for the reliability of the Bulk-Power System.

533. While we agree with EEI that EOP–001–0, Requirement R4.1 requires communications protocols to be used during emergencies, we believe, and the ERO agrees, that the communications protocols need to be tightened to ensure Reliable Operation of the Bulk-Power System. We also believe an integral component in tightening the protocols is to establish communication uniformity as much as practical on a continent-wide basis. This will eliminate possible ambiguities in communications during normal, alert and emergency conditions. This is important because the Bulk-Power System is so tightly interconnected that system impacts often cross several operating entities' areas.

534. Regarding APPA's suggestion that it may be beneficial to include communication protocols in the relevant Reliability Standard that governs those types of emergencies, we direct that it be addressed in the Reliability Standards development process.

535. In response to MISO's contention that Blackout Report Recommendation No. 26 has been fully implemented, we note that Recommendation No. 26 addressed two matters. We believe MISO is referring to the second part of the recommendation requiring NERC to ''[u]pgrade communication system hardware where appropriate'' instead of tightening communications protocols. While we commend the ERO for taking appropriate action in upgrading its NERCNet, we remind the industry to continue their efforts in addressing the first part of Blackout Recommendation No. 26.

536. Accordingly, we direct the ERO to either modify COM–002–2 or develop a new Reliability Standard that requires tightened communications protocols, especially for communications during alerts and emergencies.

v. Other Issues

(a) Comments

537. Santa Clara requests clarification whether the phrase ''Such communications shall be staffed and available'' in Requirement R1 applies only to operating staff available on site at all times or includes repair personnel who are available only on an on-call basis.

538. FirstEnergy asks that the Reliability Standard specify what is

[227] Blackout Report at 107.

[228] *Id.* at 141.

[229] NOPR at P 255.

[230] EOP–001–0, Requirement R4 provides, in relevant part, that: ''[e]ach Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plan shall include [c]ommunication protocols to be used during emergencies.''

meant by ''staffed'' and states that the term should not require a physical presence at all facilities at all times because some units, such as peaking units, are not staffed 24 hours a day. In addition, FirstEnergy suggests that, because nuclear units are already subject to communications requirements in their operating procedures, their compliance with NRC operating procedures should be deemed in compliance with the NERC Reliability Standards.

539. Similarly, Six Cities states that, to avoid unnecessary staffing burdens, particularly for smaller entities, the Commission should direct NERC to clarify COM–002–2 by providing that identification of an emergency contact person on call to respond to real-time emergency conditions will constitute adequate compliance.

(b) Commission Determination

540. Santa Clara, FirstEnergy and Six Cities suggest specific new improvements to the Reliability Standards. As stated above, such comments should be considered as the ERO modifies the Reliability Standards in the Reliability Standards development process.

vi. Summary of Commission Determination

541. While the Commission identified concerns regarding COM–002–2, the proposed Reliability Standard serves an important purpose by requiring users, owners and operators to implement the necessary communications and coordination among entities. Accordingly, the Commission approves Reliability Standard COM–002–2 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to COM–002–2 through the Reliability Standards development process that: (1) Expands the applicability to include distribution providers as applicable entities; (2) includes a new Requirement for the reliability coordinator to assess and approve actions that have impacts beyond the area view of a transmission operator or balancing authority [231] and (3) requires tightened communications protocols, especially for communications during alerts and emergencies. Alternatively, with respect to this final issue, the ERO may develop a new Reliability Standard that responds to Blackout Report Recommendation No. 26 in the manner described above. Finally, we direct the ERO to include APPA's suggestions to complete the Measures and Levels of Non-Compliance in its modification of COM–002–2 through the Reliability Standards development process.

4. EOP: Emergency Preparedness and Operations

542. The Emergency Preparedness and Operations (EOP) group of proposed Reliability Standards consists of nine Reliability Standards that address preparation for emergencies, necessary actions during emergencies and system restoration and reporting following disturbances.

a. Emergency Operations Planning (EOP–001–0)

543. NERC's proposed Reliability Standard EOP–001–0 requires each transmission operator and balancing authority to develop, maintain and implement a set of plans to mitigate operating emergencies. These plans must be coordinated with other transmission operators and balancing authorities and the reliability coordinator.

544. In the NOPR, the Commission proposed to approve Reliability Standard EOP–001–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to EOP–001–0 that: (1) Includes the reliability coordinator as an applicable entity with responsibilities as described above; (2) clarifies the 30-minute requirement in Requirement R2 of the Reliability Standard to state that load shedding should be capable of being implemented as soon as possible and much less than 30 minutes and (3) includes definitions of system states to be used by the operators, such as transmission-related ''normal,'' ''alert,'' and ''emergency'' states, provides criteria for entering into these states and identifies the authority that will declare these states.

545. Most of the comments address the specific modifications and concerns raised by the Commission in the NOPR. Below, we address each topic separately, followed by an over-all conclusion and summary.

i. Applicability to reliability coordinators

(a) Comments

546. MRO states that it is necessary to include reliability coordinators as applicable entities because reliability coordinators have a wide-area view. FirstEnergy also supports making the proposed Reliability Standard applicable to the reliability coordinator. FirstEnergy states the reliability coordinator should take an active role and should have clearly defined, specific responsibilities for coordinating and implementing emergency operations plans. In addition, FirstEnergy states that inclusion of the reliability coordinator as an applicable entity removes ambiguity that may exist concerning the reliability coordinator's role and its responsibilities during restoration activities.

547. SoCal Edison agrees that certain aspects of EOP–001–0 should be applicable to reliability coordinators; however, it proposes that NERC, through the stakeholder process, should receive input from stakeholders on which requirements should be exclusive to the transmission operator or balancing authority with the reliability coordinator responsible only for collecting and incorporating this information into its overarching plan. MISO, on the other hand, questions the need for the proposed modification, contending that the reliability coordinators have parallel responsibilities laid out in other EOP Reliability Standards.

(b) Commission Determination

548. In the NOPR, we stated that the proposed Reliability Standard applies to transmission operators and balancing authorities, that the applicability portion of the Reliability Standard is sufficiently clear as to who must comply with the filed version of the Reliability Standard and that the Reliability Standard can be enforced against these entities.[232] However, we recognized commenters' concerns that the Reliability Standard does not assign a role to the reliability coordinator, which is the highest level of authority responsible for reliable operation of the Bulk-Power System and which has a wide-area view. MISO contends that EOP–001–0 need not apply to reliability coordinators because they have parallel responsibilities in other EOP Reliability Standards. We disagree. Given the importance NERC attributes to the reliability coordinator in connection with matters covered by EOP–001–0, the Commission is persuaded that specific responsibilities for the reliability coordinator in the development and coordination of emergency plans must be included as part of this Reliability Standard. While balancing authorities and transmission operators are capable of developing, maintaining and implementing plans to mitigate

[231] This Requirement could, for example, be included in COM–002–2 or in an operating Reliability Standard.

[232] NOPR at P 272.

operating emergencies for their specific areas of responsibility, unlike reliability coordinators, they do not have wide-area views.

549. Further we agree with SoCal Edison that clear direction is needed on which requirements should be exclusive to transmission operators and balancing authorities with the reliability coordinator being responsible for incorporating this information into its overarching plan. Accordingly, the Commission finds the reliability coordinator is a necessary entity under EOP–001–0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity. In addition, the ERO should consider SoCal Edison's suggestion in the ERO's Reliability Standards development process.

ii. Clarification of the 30-minute Load Shedding Requirement

(a) Comments

550. NERC comments that the proposed directive to clarify the 30-minute requirement in Requirement R2 presumes that all manual load shedding can be performed by supervisory control. It states that, in many systems, shedding load requires actions by field personnel who must be dispatched to a site. NERC recognizes the reliability benefit of being able to shed greater amounts of load in seconds or minutes but contends that the amount of load shedding under remote supervisory control and the timing requirements should be vetted through industry experts based on good utility practice. While acknowledging that the proposed modification is appropriate because it corresponds to current good utility practice and widely held interpretations of the requirement to shed load, FirstEnergy, like NERC, notes that loads that does not have SCADA cannot be shed within 30 minutes because field staff must be dispatched. It proposes that the Reliability Standard should specify that, for loads that do not have SCADA, the implementation plan must be initiated, but not necessarily completed, within 30 minutes. Similarly, MidAmerican is concerned that if load shedding is to be performed in much less than 30 minutes it will require automatic load shedding which may trigger when not required leading to less reliability under certain conditions. MidAmerican proposes a modification to specifically permit load shedding with non-automatic schemes.

551. Xcel states that the proposed modification is unnecessary because there are many different options besides load shedding that could be implemented to alleviate IROL violations within 30 minutes. It adds that load shedding is the option of last resort and that the timing for implementation of load shedding would be better addressed in proposed Reliability Standard EOP–003–1. EEI and California PUC state that not all load reduction schemes should be required to be operable within 30 minutes; only those used for emergency operations. APPA states that the 30-minute interval was selected based on industry consensus and, rather than dismiss this consensus, the Commission should instruct NERC to reconsider the 30-minute requirement and either modify it or better explain why it is the appropriate time period for the requirement. MISO questions what would be achieved by the proposed modification and states that operators do not intentionally delay taking action when required.

552. International Transmission and PG&E state that shedding load ''as soon as possible and much less than 30 minutes'' is vague and unenforceable. International Transmission proposes shedding of load ''as soon as possible when required to mitigate an IROL violation, but in no case in more than 30 minutes.''

(b) Commission Determination

553. The proposed Reliability Standard states that the transmission operator shall have an emergency load reduction plan for all identified IROLs and that the load reduction plan must be capable of being implemented within 30 minutes. In the NOPR, we proposed to direct NERC to modify EOP–001–0 to clarify the 30-minute requirement in Requirement R2 to state that load shedding should be capable of being implemented as soon as possible and in much less than 30 minutes.[233] The intent was to have a requirement that precludes waiting until the 29th minute to begin implementation.

554. In response to the concerns of commenters, the Commission clarifies that the proposed modification does not require that SCADA or its equivalent be installed for all loads. Rather, SCADA would be required only for those loads necessary to mitigate IROL violations and to maintain reliable operations. As we stated in the NOPR, the Commission understands that it is not the intent of the Reliability Standard to require the shedding of all available load within 30 minutes, but rather only the amount necessary to correct system emergencies.[234] Thus the Commission agrees with EEI and California PUC that not all load reduction schemes should be required to be operable within 30 minutes but only those used for emergency operations.

555. Further, as Xcel recognizes, load shedding is the option of last resort and there may be other options available to alleviate IROL violations within 30 minutes. The ERO should consider these other options as it works through the Reliability Standards development process to modify EOP–001–0.

556. With regard to the wording of the proposed modification stating that load shedding should be capable of being implemented ''as soon as possible and in much less than 30 minutes,'' the Commission agrees with PG&E and International Transmission that this language may be unclear and unduly subjective. In the NOPR, we stated that the reference to 30 minutes could suggest that anything up to that limit was acceptable and proposed the modification to emphasize our concern that implementation was expected much sooner than in 30 minutes. International Transmission's suggested rewording addresses our concern. Accordingly, we direct the ERO to develop a modification through the Reliability Standards development process clarifying that when the load reduction plan of Requirement R2 involves load shedding, such load shedding be capable of being implemented as soon as possible when required to mitigate an IROL violation but in no case in more than 30 minutes.

557. Finally, in response to APPA's comments, as stated in the NOPR,[235] the Commission accepts the 30-minute requirement as a reasonable period within which operators should return the system to a reliable operating state. However, in order to satisfy this Requirement, when load shedding is the only viable option, the Commission believes that operators must have the capability through SCADA or other equivalent means to shed appropriate amounts of load in the desired locations as soon as possible to mitigate IROL violations but in no case in more than 30 minutes.[236]

iii. Definitions of System States

(a) Comments

558. FirstEnergy states that it may be difficult to define system states that cover all operating conditions, but nonetheless recognizes that the standardization of these states is a first step to bringing clarity to operators concerning system conditions and the

[233] *Id.* at P 273.

[234] *Id.*

[235] *Id.* at P 995.

[236] *Id.*

resulting actions they are expected to take. California PUC, on the other hand, states that imposing uniform definitions for ''normal,'' ''alert'' and ''emergency'' states is impractical and counterproductive. California PUC claims that trying to define in advance all contingencies that the system may face is probably infeasible and argues that improved real-time monitoring of the grid is the preferred approach for quick identification and correction of problems.

559. ISO–NE states that it is important to define system states but that such definitions should not be implemented until a ''pilot program'' is field tested. ISO–NE explains that after such a pilot program is conducted operators would need to make changes to their policies and procedures, including operator training, to make sure that their practices are administered in a secure and well-understood fashion.

(b) Commission Determination

560. In the NOPR, the Commission stated that clearly defined system states incorporated into real-time operation can significantly improve operator recognition of emergency conditions, rapid and accurate response and recovery to normal system conditions.[237]

561. The Commission recognizes that the triggering events and the nature of the emergency states may be different for different systems; however, we find that a clearly defined set of system states will help operators proactively avert escalations of system disturbances and cascading outages. Further, operators, the ERO and regulators will better understand how reliably the system is operating and how it performed historically if statistics can be collected based on well-defined system states. We find it reasonable for the ERO, through the stakeholder process, to develop a well-defined set of uniform, continent-wide system states that can be understood by transmission operators, balancing authorities, reliability coordinators and the ERO to correspond to specific, predetermined levels of urgency.

562. As we noted in the NOPR, some control areas define and effectively use more than the ''normal,'' ''alert'' and ''emergency'' system states included in the Blackout Report recommendation.[238] We proposed that the ERO determine the optimum number of system states to be employed continent-wide and to consider the addition of the restoration state.[239] Accordingly, we direct the ERO to determine the optimum number of continent-wide system states and their attributes and to modify the Reliability Standard through the Reliability Standards development process to accomplish this objective.

563. Further, we agree with ISO–NE that the proposed modification should be field-tested and that policies and procedure be put in place, including operator training, before any processes for continent-wide system states are implemented. Such testing will help assure that all applicable entities and their personnel understand how the terms will be used and will allow operators to train staff to make any necessary changes to their policies and procedures. We direct the ERO to consider such a pilot program as it modifies EOP–001–0 through the Reliability Standards development process.

iv. Other issues

(a) Comments

564. ISO–NE raises two additional concerns with the proposed Reliability Standard. First, it states that activities outlined in Requirement R7.4, including coordinating fuel conservation and arranging for fuel deliveries, are not functions that independent transmission operators and balancing authorities typically perform. Second, ISO–NE notes that Requirement R5 provides that each transmission operator and balancing authority must include applicable elements of Attachment 1 of EOP–001–0 in an emergency plan. However, according to ISO–NE, the elements identified in Attachment 1 are characterized as ''for consideration'' and are not mandatory. ISO–NE argues that the proposed Reliability Standard should be clarified to indicate that the actual emergency plan elements, and not the ''for consideration'' elements of Attachment 1, should be the basis for compliance.

(b) Commission Determination

565. With regard to ISO–NE's concern that certain activities outlined in Requirement R7.4 are not functions normally performed by independent transmission operators and balancing authorities, the Commission understands that this Requirement covers either delivery of fuel or delivery of electrical energy from remote systems. While arranging for fuel deliveries may be outside of the functions that ISOs and RTOs perform, the requirement to arrange deliveries of electrical energy from remote systems is a function they normally perform. Because an ISO or RTO may choose to either deliver fuel or electrical energy from remote systems, Requirement R7.4 will not burden ISOs and RTOs with functions they do not normally perform.

566. The Commission agrees with ISO–NE that the Reliability Standard should be clarified to indicate that the actual emergency plan elements, and not the ''for consideration'' elements of Attachment 1, should be the basis for compliance. However, all of the elements should be considered when the emergency plan is put together.

v. Summary of Commission Determination

567. Accordingly, the Commission concludes that Reliability Standard EOP–001–0 is just, reasonable, not unduly discriminatory or preferential and in the public interest and approves it as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–001–0 through the Reliability Standards development process that: (1) Includes the reliability coordinator as an applicable entity with responsibilities as described above; (2) clarifies the 30-minute requirement in Requirement R2 of the Reliability Standard to state that load shedding should be capable of being implemented as soon as possible but in no more than 30 minutes; (3) includes definitions of system states to be used by the operators, such as transmission-related ''normal,'' ''alert'' and ''emergency'' states, provides criteria for entering into these states, and identifies the authority that will declare these states and (4) clarifies that the actual emergency plan elements, and not the ''for consideration'' elements of Attachment 1, should be the basis for compliance. Further, the Commission directs the ERO to consider a pilot program for system states, as discussed above.

b. Capacity and Energy Emergencies (EOP–002–2)

568. EOP–002–2 applies to balancing authorities and reliability coordinators and is intended to ensure that they are prepared for capacity and energy emergencies.[240] The Reliability Standard requires that balancing authorities have the authority to bring

[237] *Id.* at P 275.

[238] *Id.* at P 276.

[239] *Id.*

[240] In its November 15, 2006, filing, NERC submitted EOP–002–2, which supercedes the Version 1 Reliability Standard. EOP–002–2 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, EOP–002–2.

all necessary generation on line, communicate about the energy and capacity emergency with the reliability coordinator and coordinate with other balancing authorities. EOP–002–2 includes an attachment that describes an emergency procedure to be initiated by a reliability coordinator that declares one of four energy emergency alert levels to provide assistance to the LSE.

569. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to the Reliability Standard that: (1) Addresses emergencies resulting not only from insufficient generation but also from insufficient transmission capability, including situations where insufficient transmission impacts the implementation of the capacity and energy emergency plan; (2) identifies DSM in Requirement R6 as one possible remedy that a balancing authority may use to bring it in compliance with control performance and disturbance control Reliability Standards and (3) includes a clear warning that the TLR procedure is an inappropriate and ineffective tool to mitigate IROL violations or for use in emergency situations.

570. Most of the comments address the specific modifications and concerns raised by the Commission in the NOPR. Below, we address each topic separately, followed by an over-all conclusion and summary.

i. Insufficient Transmission Capability

(a) Comments

571. MRO believes that the definition for the term ''insufficient transmission capability'' should be clarified because insufficient transmission capability could be due to a thin spot in the interconnection, prior outages or storm damage.

(b) Commission Determination

572. As we stated in the NOPR, neither EOP–002–2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies.[241] The Commission agrees with MRO that ''insufficient transmission capability'' could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process.

ii. Demand-Side Management

(a) Comments

573. FirstEnergy states that it is appropriate to include demand-side resources as another tool for balancing authorities to use in meeting control performance and disturbance control Reliability Standards. It states, however, that in order to qualify, the demand-side resource options must meet similar technical requirements as generation resource options. Comverge recommends that the terms ''demand response'' and ''curtailable loads'' be specifically added to R3, R4 and R6.3 and Alert Level 1 to ensure that they are included in the list of resources that will be controlled during capacity and energy emergencies. APPA contends that Requirement R6.6 adequately accounts for the use of demand-side remedies to address emergencies. As such, APPA opposes the Commission's proposal as being unduly prescriptive. Also ISO–NE contends that the proposed modifications effectively dictate a specific means to solve the underlying problems instead of leaving it to the responsible entities to determine how to achieve the reliability objective. A proper recommendation would be to make the requirement resource-neutral.

(b) Commission Determination

574. The Commission agrees with FirstEnergy that for demand-side resources to qualify as another tool for balancing authorities to use in meeting control performance and disturbance control Reliabilty Standards, they must meet comparable technical performance requirements as generation resource options. In response to comments from Comverge and APPA, the Commission believes that curtailable loads are adequately addressed in Requirement R6 of the Reliability Standard but that demand response is not covered.[242] Demand response covers considerably more resources than interruptible load. Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.

iii. Warning regarding TLR procedure

(a) Comments

575. MRO states that it is very important that all concerned parties realize that TLR is not a first line of defense to mitigate IROL violations. Entergy and MidAmerican agree that TLR procedures are not effective to mitigate IROL violations or for use in emergency situations. EEI supports the Commission's proposed modifications to the Reliability Standard; however, EEI along with Entergy, MidAmerican and APPA, believes that the TLR process is effective in avoiding and mitigating potential IROL violations. These commenters request that the Commission clarify the proposed modification so that it does not foreclose such use of the TLR process.

576. International Transmission states that TLR can be an effective and appropriate means to mitigate IROL violations or for use in emergency situations and therefore EOP–002–2 should not preclude the use of TLR when its use is warranted. MISO states that, while TLR is not the preferred method of responding to emergencies, an operator should not be precluded from implementing TLR during emergencies. It argues that TLR may be appropriate when events develop slowly or when an entity is affected by external transactions and has exhausted all control actions or needs to reserve some control actions for contingencies.

577. APPA contends that the specific direction provided in this proposed modification intrudes on NERC's role as a standard setting agency and would be better framed as a direction to NERC to investigate the concern and revise the Reliability Standard accordingly. Similarly, while ISO-NE supports the Commission's conclusion that reliance on TLR procedures can be inappropriate, it recommends that the proposed Reliability Standard would be improved if it did not specify the operating method required to achieve compliance. ISO–NE also believes that the Commission should direct NERC to allow the responsible entities flexibility in the means by which they achieve compliance with the Reliability Standard.[243]

(b) Commission Determination

578. A number of commenters agree that the TLR procedure is an inappropriate and ineffective tool for mitigating actual IROL violations or for

[241] NOPR at P 284.

[242] Requirement R6 provides, in pertinent part: ''R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: R6.3. Interrupting interruptible load and exports.''

[243] ISO–NE also notes that in the first line of Requirement R7 the reference to ''R7'' should be to ''R6.''

use in emergency situations.[244] On the other hand, International Transmission believes the TLR procedure can be an appropriate and effective tool to mitigate IROL violations or for use in emergency situations and MISO argues that operators should not be precluded from implementing the TLR procedure during emergencies. The Commission disagrees. As explained in the NOPR and in the Blackout Report, actions undertaken under the TLR procedure are not fast and predictable enough for use in situations in which an operating security limit is close to being, or actually is being, violated. As such the Commission cannot agree with International Transmission and MISO. However, the Commission agrees with APPA, EEI, Entergy and MidAmerican that the TLR procedure may be appropriate and effective for use in managing potential IROL violations. Accordingly, the Commission will maintain its direction that the ERO modify the Reliability Standard to ensure that the TLR procedure is not used to mitigate actual IROL violations.

579. As to APPA's comment that we are intruding on NERC's role as a standard-setting agency, we have authority to direct the ERO to submit a modification and, in this instance, requiring the ERO to ''investigate the concern'' first is unnecessary. The issue is narrowly-framed and the comments identify no points requiring the approach suggested by APPA. In response to ISO–NE, we are precluding use of TLR procedures at times of actual IROL violations, but are not otherwise specifying permissible responses.

iv. Other issues

580. ISO–NE states that Requirement R2 essentially requires the same actions covered by ISO–NE Operating Procedure No. 4. ISO–NE is concerned that a strict approach to auditing compliance with the Reliability Standard could result in a finding that ISO–NE was in violation of the Reliability Standard if it skipped a particular action under its emergency plan even though that action was not called for under ISO–NE procedures. ISO–NE requests that the Commission direct NERC to clarify that a system operator has discretion not to implement every action specified in its capacity and energy emergency plans when other appropriate actions are possible.

581. FirstEnergy claims that Requirement R1 may impose overlapping obligations and authority on reliability coordinators and balancing authorities who may have the same, partial or whole footprint and who are both likely to respond to the same emergency.

582. APPA notes that revised Reliability Standard EOP–002–2, filed by NERC on November 15, 2006, includes new Measures for some of the requirements but not all the requirements. APPA states that NERC should be directed to include Measures related to Requirements R4, R5, R6, R7 and R9.1.

(a) Commission Determination

583. The Commission finds that the issues raised by ISO-NE should be addressed through the Reliability Standards development process. As to FirstEnergy's concern with Requirement R1, the reliability coordinator has the highest level of authority. Accordingly, the Commission directs that the ERO, through the Reliability Standards development process, address ISO-NE's concern. Further, we direct the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard.

v. Summary of Commission Determination

584. Accordingly, the Commission approves Reliability Standard EOP–002–2 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–002–2 through the Reliability Standards development process that: (1) Addresses emergencies resulting not only from insufficient generation but also from insufficient transmission capability particularly where this affects the implementation of the capacity and energy emergency plan; (2) includes all technically feasible resource options, including demand response and generation resources, in the management of emergencies and (3) ensures that the TLR procedure is not used to mitigate actual IROL violations.

c. Load Shedding Plans (EOP–003–1)

585. EOP–003–1 deals with load shedding plans and requires that balancing authorities and transmission operators operating with insufficient transmission and generation capacity have the capability and authority to shed load rather than risk a failure of the Interconnection.[245] It includes requirements to establish plans for automatic load shedding for underfrequency or undervoltage, manual load shedding to respond to real-time emergencies and communication with other balancing authorities and transmission operators.

586. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to EOP–003–0 that: (1) Specifies the minimum load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented; (2) requires periodic drills of simulated load shedding and (3) contains Measures and Levels of Non-Compliance.

587. Most of the comments address the specific modifications and concerns raised by the Commission in the NOPR. Below, we address each topic separately, followed by an over-all conclusion and summary.

i. Minimum load shedding and maximum delay

(a) Comments

588. FirstEnergy and APPA agree that NERC should modify EOP–003–1 to specify the minimum load shedding capability and the maximum amount of delay. However, FirstEnergy adds that Requirement R8, which states that load shedding actions must be taken in a ''time frame adequate for responding to the emergency,'' is ambiguous and difficult to substantiate. NERC acknowledges that significant improvements can be made to the EOP Reliability Standards to establish criteria for the provision of load shedding capability, but it states that requiring a specific minimum amount of load (MW) or percentage of load that must be capable of being shed and the maximum amount of time delay is as likely to reduce reliability as it is to increase it. NERC contends that the electric characteristics of local systems and loads must be considered in designing manual and automatic load shedding capabilities. Accordingly, it proposes that the Commission direct NERC to review industry best practices and propose requirements in the Reliability Standards to ensure that adequate load shedding capabilities are provided to protect the Bulk-Power System without causing adverse impacts associated with unnecessary shedding of firm load.

[244] *See, e.g.*, APPA, EEI, Entergy and MidAmerican.

[245] In its November 15, 2006, filing, NERC submitted EOP–003–1, which supercedes the Version 0 Reliability Standard. EOP–003–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, EOP–003–1.

589. SoCal Edison states that in certain circumstances, but not in all cases, it would be valuable to have a minimum limit established for the amount of load shedding an entity is to accomplish. It suggests that the specific requirements should be derived based on studied conditions.

590. Xcel, ISO–NE, TVA and International Transmission do not support a nationwide Reliability Standard for minimum load shedding and maximum delay for implementing load shedding because there are large variations in load, resources and system configuration and characteristics across the continent. TVA states that these parameters should be determined based on studies of the specific transmission systems and applicable contingency events. MISO states that it is not clear what is intended or achieved by this requirement because balancing authorities and transmission operators should already have the ability to shed, by some means, all load within their area and the timing requirements are specified in the IROL-related Reliability Standards.

591. California PUC is concerned that the proposed modification assumes that load shedding at the transmission level is the only or the primary way to address system emergencies. SDG&E recommends that the maximum delay for shedding load should begin when the transmission operator or balancing authority has actual knowledge of the circumstances that would precipitate load shedding.

(b) Commission Determination

592. Shedding of firm load is an operating measure of last resort to contain system emergencies and prevent cascading. System operators must have the capability to shed load in a timely manner to return the system to a stable condition. The Commission disagrees with NERC's contention that requiring a specific minimum amount of load that must be capable of being shed and the maximum amount of delay is as likely to reduce reliability as it is to increase it. As stated in the NOPR, the actual amount of load to be shed, the location and the time frame will be at the discretion of the system operator based on the nature of the system problem and the operator's assessment of corrective actions required.[246] However, if the capability to shed sufficient load in locations where it is required and in a timely manner is not available to the system operator, then the risk of uncontrolled failure of system elements or cascading outages is increased.

593. While the Reliability Standard requires transmission operators and balancing authorities to be capable of load shedding in a time frame adequate for responding to emergencies, this could be clearer, as noted by FirstEnergy. As mentioned by NERC, significant improvements can be made to the Reliability Standard to establish criteria for the provision of load shedding capability. We agree.

594. Several commenters state that they do not support a nationwide Reliability Standard for minimum load shedding capability and maximum delay in implementing load shedding because these parameters are dependent on system configurations and load and resource characteristics across the continent, and as such, must be determined based on system studies.[247] The Commission agrees that the minimum load shedding capability must take into account system characteristics and topology, however the maximum time delay before load shedding can be implemented is independent of system characteristics and is governed by what is considered to be feasible.

595. California PUC is concerned that the proposed modification on load shedding assumes that load shedding at the transmission level is the only or preferred way to address system emergencies. The Commission clarifies that this assumption is incorrect and agrees with California PUC that load shedding at the distribution level has the minimum societal and economic impact.

596. The Commission concludes that the Reliability Standard needs to be modified to ensure that adequate load shedding capabilities are provided so that system operators have an effective operating measure of last resort to contain system emergencies and prevent cascading. The Commission recognizes that the amount of load shedding capability required is dependent on system characteristics and therefore it may not be feasible to have a uniform nationwide load shedding capability. This, however, does not preclude a uniform nationwide criterion on the methodology for establishing load shedding capability that would specify the minimum amount of load shedding capability that should be provided based on system characteristics and conditions and the maximum amount of delay before load shedding can be implemented. The Commission directs the ERO to address the minimum load and maximum time concerns of the Commission through the Reliability Standards development process. We suggest that a review of industry best practices would be useful in developing nationwide critera.

ii. Periodic drills of simulated load shedding

(a) Comments

597. California PUC states that, since load shedding at the distribution level has the minimum societal and economic impact, the Reliability Standard should require all neighboring distribution or transmission utilities to participate in annual drills when requested by an ISO or other bulk power authority. Northern Indiana and FirstEnergy support mandating periodic drills of simulated load shedding; however, FirstEnergy states that the drill requirements should include simulated load shed via a simulator or table-top exercise, not an actual deployment of manpower, and that these drill requirements should be included in the PER–005–0 Reliability Standard instead of EOP–003–1. PER–005–0 only involves training of control room personnel, whereas these drills should also include testing the readiness and functionality of procedures and personnel outside of the control room.

(b) Commission Determination

598. As suggested by California PUC, periodic drills of simulated load shedding should involve all participants required to ensure successful implementation of load shedding plans. As such, the drills should extend beyond system operators to distribution operators and LSEs. The Reliability Standard should require periodic drills by entities subject to section 215, and require those entities to seek participation by other entities. The drills should test the readiness and functionality of the load shedding plans, including, at times, the actual deployment of personnel. Therefore the Commission disagrees with FirstEnergy that the requirement for periodic drills of simulated load shedding should be incorporated into the new PER–005–0 Reliability Standard that is currently being drafted to address operator training.

iii. Other issues

(a) Comments

599. Santa Clara states that since automatic load shedding for undervoltage conditions is not required in most parts of the West and possibly in other areas of the country,

[246] NOPR at P 294.

[247] *See* Xcel, ISO–NE, TVA, International Transmission and MISO.

Requirement R2 should be modified to include the words ''as applicable per the Regional Reliability Organization.'' In addition, APPA states that NERC should consider requiring balancing authorities and transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners. ISO-NE proposes that NERC establish coordinated trip settings within and among balancing authorities for each interconnection.

600. While EEI generally supports the proposed modifications, it believes that the proposal for senior management to post letters to safeguard operators who shed load in accordance with approved guidelines does not respond to or meet the needs reflected in the Blackout Recommendation No. 8. EEI points out that, under other provisions of the FPA, the Commission has approved liability limiting provisions for some operators that appears to be consistent with the Blackout Report Recommendation No. 8, but has rejected other similar protections. EEI requests that the Commission explicitly state that transmission operators taking action in compliance with the load shedding provisions of Commission approved Reliability Standards will be protected from retaliatory actions, including legal actions.

(b) Commission Determination

601. Regarding Santa Clara's concern that undervoltage load shedding is not required in most parts of WECC and that Requirement R2 should be modified to reflect this, the Commission notes that Requirement R2 states that each transmission operator and balancing authority shall establish plans for automatic load shedding for underfrequency or undervolatge conditions. The Commission clarifies that the Reliability Standard does not mandate undervoltage load shedding unless needed for Reliable Operation.

602. We also note that APPA and ISO-NE raise issues regarding coordination of trip settings and automatic and manual load shedding plans. The Commission directs the ERO to consider these comments in future modification to the Reliability Standard through the Reliability Standards development process.

603. EEI seeks adoption of a provision to shield transmission operators from liability when they take action in compliance with the load shedding provisions of the Reliability Standards. Consistent with our discussion of Blackout Report Recommendation No. 8 in the Common Issues section of this Final Rule, the Commission will not adopt new liability protections.[248] According to the Task Force, no further action is needed to implement that recommendation because some states already have appropriate protection against liability suits.[249] Further, in Order No. 890, we have already declined to provide a uniform federal liability standard.

iv. Summary of Commission Determination

604. The Commission approves proposed Reliability Standard EOP–003–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–003–1 through the Reliability Standards development process that: (1) Includes a requirement to develop specific minimum load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented based on an overarching criteria that take into account system characteristics and (2) requires periodic drills of simulated load shedding.

d. Disturbance Reporting (EOP–004–1)

605. EOP–004–1 establishes requirements for reporting system disturbances to the regional reliability organization and the ERO.[250] It also establishes requirements for the analysis of these disturbances.

606. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to the Reliability Standard that: (1) Includes any requirements necessary for users, owners and operators of the Bulk-Power System to provide data that will assist NERC in the investigation of a blackout or disturbance and (2) includes Measures and Levels of Non-Compliance.

i. Comments

607. EEI and FirstEnergy support the Commission's proposed modifications to the Reliability Standard. EEI states that data reporting requirements and other process requirements should be contained in enforceable Reliability Standards. FirstEnergy states that the proposed modification corresponds to good utility practice and that explicitly stating the requirement to provide data to NERC brings clarity to the expectations of NERC and the Commission.

608. APPA is concerned about the scope of Requirement R2 because, in its opinion, Requirement R2 appears to impose an open-ended obligation on entities such as generation operators and LSEs that may have neither the data nor the tools to promptly analyze disturbances that could have originated elsewhere. APPA proposes that Requirement R2 be modified to require affected entities to promptly begin analyses to ensure timely reporting to NERC and DOE.

609. Xcel expresses concern regarding what constitutes a reportable event for each applicable entity and recommends that the Reliability Standard be revised to define what a reportable event is for each entity that has reporting obligations. Further, Xcel states that the requirement in Requirement R3.4 for a final report within 60 days may not be feasible given the current WECC process, which among other things, requires the creation of a group to prepare the report and a 30-day posting of a draft report before it becomes final. Xcel also states that if the ultimate purpose of the report is to provide information to avoid a recurrence of a system disturbance, then the Reliability Standard should be revised to require the distribution of the report to similarly situated entities.

610. FirstEnergy states that, since nuclear units have their own NRC reporting procedures covering the Requirements under EOP–004–1, the Reliability Standard should specify that compliance with such operating procedures is sufficient to satisfy the requirements of EOP–004–1. FirstEnergy also states that the title of this Reliability Standard should be changed to ''Disturbance Event Reporting'' to indicate that the events covered under this Reliability Standard include a broad range of events that go beyond the events for which reports may be required under Reliability Standard BAL–002–0.

[248] *See* Common Issues Pertaining to Reliability Standards: Blackout Report Recommendation on Liability Limitations, supra section II.E.1.

[249] U.S.-Canada Power System Outage Task Force, Final Report on Implementation of Task Force Recommendations at 22 (Oct. 3, 2006), available at *http://www.oe.energy.gov/news/blackout.htm* (''In the United States, some state regulators have informally expressed the view that there is appropriate protection against liability suits for parties who shed load according to approved guidelines.'')

[250] In its November 15, 2006, filing, NERC submitted EOP–004–1, which supercedes the Version 0 Reliability Standard. EOP–004–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, EOP–004–1.

611. APPA states that NERC's November 15, 2006 revision partially fulfills the proposed modification to include Measures and Levels of Non-Compliance. APPA notes that EOP–004–1 did not provide Measures for R2, R3.2, R3.4, R4 and R5.

ii. Commission Determination

612. Complete and timely data is essential for analyzing system disturbances. In the NOPR, the Commission proposed modifying this disturbance Reporting Standard to include requirements necessary for users, owners and operators of the Bulk-Power System to provide disturbance data, voice recordings and other information collected during the disturbance to assist NERC in the investigation of the blackout or disturbance.[251] While some commenters agree with this proposal, APPA and Xcel express concerns regarding the scope and applicability of some of the Requirements of the Reliability Standard.

613. Requirement R2 of the Reliability Standard requires reliability coordinators, balancing authorities, transmission operators, generator operators and LSEs to promptly analyze disturbances on their system or facilities. APPA is concerned that generator operators and LSEs may be unable to promptly analyze disturbances, particularly those disturbances that may have originated outside of their systems, as they may have neither the data nor the tools required for such analysis. The Commission understands APPA's concern and believes that, at a minimum, generator operators and LSEs should analyze the performance of their equipment and provide the data and information on their equipment to assist others with their analyses. The Commission directs the ERO to consider this concern in future revisions to the Reliability Standard through the Reliability Standards development process.

614. The Commission disagrees with Xcel that the Reliability Standard is unclear about what constitutes a reportable event. Attachment 1 of the Reliability Standard details the various events that would trigger the reporting requirement under this Reliability Standard.

615. FirstEnergy states that since nuclear units have their own NRC reporting requirements the Reliability Standard should specify that compliance with NRC procedures is sufficient to satisfy the obligations of this Reliability Standard. The Commission disagrees with FirstEnergy because there are situations where the ERO Reliability Standards are more stringent than the NRC procedures. In such cases, the ERO Reliability Standards must apply in addition to the NRC requirements. Also, the Commission disagrees with FirstEnergy's comment on changing this Reliability Standard's name to avoid confusion with BAL–002–0. The purpose of the Reliability Standard is clear as to the extent of the disturbances to be reported.

616. The Commission declines to address Xcel's concerns about the current WECC process. These issues should be addressed in the Reliability Standards development process or submitted as a regional difference. The Commission directs the ERO to consider all comments in future modifications of the Reliability Standard through the Reliability Standards development process.

617. In response to APPA's concern that NERC did not provide a Measure for each Requirement, we reiterate that it is in the ERO's discretion whether each Requirement requires a corresponding Measure. The ERO should consider this issue through the Reliability Standards development process.

618. While the Commission has identified concerns with regard to EOP–004–1, we believe that the proposal serves an important purpose in establishing requirements for reporting and analysis of system disturbances. Accordingly, the Commission approves Reliability Standard EOP–004–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–004–1 through the Reliability Standards development process that includes any Requirements necessary for users, owners and operators of the Bulk-Power System to provide data that will assist NERC in the investigation of a blackout or disturbance.

619. Requirement R3 addresses the reporting of disturbances to the regional reliability organizations and NERC. The Commission directs the ERO to change its Rules of Procedure to assure that the Commission also receives these reports within the same time frames as DOE.

e. System Restoration Plans (EOP–005–1)

620. EOP–005–1 deals with system restoration plans and requires that plans, procedures, and resources be available to restore the electric system to a normal condition in the event of a partial or total system shut down. The Reliability Standard requires transmission operators, balancing authorities, and reliability coordinators to have effective restoration plans, to test those plans, and to be able to restore the interconnection using them following a blackout. It also requires operating personnel to be trained in these plans.

621. In the NOPR, the Commission proposed to approve Reliability Standard EOP–005–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to EOP–005–1 that: (1) Includes Measures and (2) identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events.

i. Comments

622. APPA and EEI state that Reliability Standard EOP–005–1 is sufficient for approval as a mandatory Reliability Standard and requests that the Commission direct NERC to address missing Measures and training requirements. In addition, APPA notes that the Reliability Standard is applicable to both balancing authorities and transmission operators but the Measures and Levels of Non-Compliance elements refer only to transmission operators.

623. ISO-NE does not support adoption of the proposed Reliability Standard because, while Requirement R1 requires transmission operators to include applicable elements from Attachment 1 of EOP–005–1 in their restoration plans, Requirement R1 appears to indicate that the elements in Attachment 1 are to be included in the emergency plan only ''as applicable.'' ISO-NE states that the Reliability Standard should be clarified to indicate that the actual emergency plan elements should be the basis for compliance.

624. EEI and FirstEnergy note that the proposed modification to identify time frames for training and review of restoration plan requirements is being addressed in the proposed Reliability Standard PER–005–1 and that including this requirement in EOP–005–1 would be redundant. MISO also believes that the proposed modification is unnecessary. It states that there are already requirements for simulation-based training on emergencies and restoration and it is unclear what is meant by conducting training to prepare operators for unforeseen events.

[251] NOPR at P 304.

625. FirstEnergy states that Requirement R1 calls for a plan for a partial shutdown of the system and that there is an infinite set of events that can cause a partial shutdown. According to FirstEnergy, because the borders of a partial shutdown are difficult, if not impossible, to foresee, the Reliability Standard should specify some boundaries for analysis of partial shutdowns including an appropriate definition of the term ''partial shutdown.'' In addition, FirstEnergy states that one uniform plan for all systems is not feasible; rather the Reliability Standard should recognize that some companies already have existing plans that could be used for analyzing events. FirstEnergy also states that the Reliability Standard should provide a uniform checklist of factors to analyze, developed on a company-specific basis.

626. NRC suggests that this Reliability Standard include: (1) A requirement to record the time it takes to restore power to the auxiliary power systems of nuclear power plants; (2) a provision stating that the affected transmission operators shall give high priority to restoration of off-site power to nuclear power plants whether or not a nuclear power plant is being powered from the nuclear power plant's onsite power supply and (3) a provision stating that restoration shall not violate nuclear power plant minimum voltage and frequency requirements.

627. While not commenting on the substance of Reliability Standard EOP–005–1, MRO states that EOP–005–1, EOP–006–1 and EOP–007–0 are ordered in a confusing manner and should be renumbered. MRO reasons that since the regional coordinator has oversight responsibility for system restoration, EOP–006–1 should be first in the system restoration sequence of Reliability Standards (*i.e.*, EOP–006–1 should precede EOP–005–1). Further, MRO recommends that EOP–005–1 follow EOP–006–1 because transmission owners and balancing authorities are responsible for submitting restoration plans to the regional coordinator. MRO requests that if a reason exists for the current order, NERC should provide that reason to the Commission.

ii. Commission Determination

628. With regard to comments that the Commission's concerns are being addressed in NERC's drafting of proposed PER–005–1 Reliability Standard on operator training, we note PER–005–1 only includes Requirements on the control room personnel and not those outside of the control room. System restoration requires the participation of not only control room personnel but also those outside of the control room. These include blackstart unit operators and field switching operators in situations where SCADA capability is unavailable. As such, the Commission believes that inclusion of periodic system restoration drills and training and review of restoration plans in a system restoration Reliability Standard is the most effective way of achieving the desired goal of ensuring that all participants are trained in system restoration and that the restoration plans are up to date to deal with system changes.

629. Several commenters raise issues that should be addressed by the ERO through the Reliability Standards development process.[252] For example: whether the Measures and Levels of Non-Compliance should refer to balancing authorities; clarification of the elements that form the basis for compliance with the requirements of Attachment 1; what constitutes a partial shutdown for which restoration plans must be developed and recognition that some companies already have existing plans that could be used for analyzing events; and that the Reliability Standard should provide a uniform checklist of factors to analyze, developed on a company-specific basis. We find that consideration of these issues could be helpful in meeting the objectives of the Reliability Standard. Accordingly, the ERO should consider these concerns in future revisions of the Reliability Standard through the Reliability Standards development process.

630. NRC raises several issues concerning the role and priority that nuclear power plants should have in system restorations. The Commission shares these concerns and directs the ERO to consider the issues raised by NRC in future revisions of the Reliability Standard through the Reliability Standards development process. In addition the Commission directs the ERO to gather data, pursuant to § 39.5(f) of the Commission's regulations, from simulations and drills of system restoration on the time it takes to restore power to the auxiliary power systems of nuclear power plants under its data gathering authority and report that information to the Commission on a quarterly basis.

631. We find that the Reliability Standard adequately addresses operating personnel training and system restoration plans to ensure that transmission operators, balancing authorities and reliability coordinators are prepared to restore the Interconnection following a blackout. Accordingly, the Commission approves Reliability Standard EOP–005–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–005–1 through the Reliability Standards development process that identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events and gathers the data from simulations and drills of system restoration on the time it takes to restore power to the auxiliary power systems of nuclear power plants under its data gathering authority and report that information to the Commission on a quarterly basis.

f. Reliability Coordination-System Restoration (EOP–006–1)

632. Proposed Reliability Standard EOP–006–1 addresses reliability coordination and system restoration.[253] It establishes specific requirements for reliability coordinators during system restoration, and it states that reliability coordinators must have a coordinating role in system restoration to ensure that reliability is maintained during restoration and that priority is placed on restoring the Interconnection.

633. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to the Reliability Standard that: (1) requires that the reliability coordinator be involved in the development of and approves restoration plans and (2) includes Measures and Levels of Non-Compliance.

i. Comments

634. APPA states that Reliability Standard EOP–006–1, which NERC filed on November 15, 2006, includes the required Measures and Levels of Non-Compliance and as such APPA agrees that EOP–006–1 should be approved as mandatory and enforceable. In addition, APPA does not oppose industry consideration of a requirement that reliability coordinators be involved in the development and approval of restoration plans.

[252] *See* APPA, ISO–NE, FirstEnergy and MRO.

[253] In its November 15, 2006, filing, NERC submitted EOP–006–1, which supercedes the Version 0 Reliability Standard. EOP–006–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, EOP–006–1.

635. EEI states that Requirements R4 and R11 of EOP–005–1 already address reliability coordinator involvement in the development and approval of transmission operator system restoration plans. Further, while EEI agrees that the reliability coordinator's role is appropriate, it believes that the asset owner, as the entity that ultimately bears responsibility for restoration capabilities, should also have authority to develop and maintain the plans. MISO believes that it is unnecessary to modify the Reliability Standard to involve the reliability coordinator because there is already a requirement in EOP–005–1 for balancing authorities and transmission operators to coordinate their plans with the reliability coordinator.

636. Xcel disagrees that the reliability coordinator should be involved with the development of restoration plans because the reliability coordinator typically does not have the knowledge of the details necessary to develop the plans in contrast to the balancing authorities and the transmission operators. Instead it proposes that the reliability coordinator develop its own plans and coordinate that with the balancing authority and transmission operator's plans.

ii. Commission Determination

637. The reliability coordinator is the highest level of authority that is responsible for the reliable operation of the Bulk-Power System. Given the importance of this role in connection with matters covered by EOP–006–1, the Commission believes that the reliability coordinator must be involved in the development and approval of the restoration plans. The current Reliability Standard only requires that the reliability coordinator be aware of the restoration plan of each transmission operator in its area. The Commission disagrees with EEI and MISO, who contend that the reliability coordinator's role in the transmission operator's restoration plan is covered in EOP–005–1. EOP–005–1 only requires coordination with the reliability coordinator, and during actual system restoration, EOP–005–1 requires approval from the reliability coordinator to resynchronize isolated areas with other isolated areas.

638. In response to comments by Xcel, the Commission believes that while the reliability coordinator may not have the level of detailed knowledge that the balancing authorities and transmission operators may have for setting-up the stable islands required under restoration plans, the reliability coordinator is in the best position to determine how those stable islands should be resynchronized with each other and the rest of the interconnected system.

639. The Commission finds that the Reliability Standard adequately addresses the goals of effective and efficient reliability coordination and system restoration. Accordingly, the Commission approves Reliability Standard EOP–006–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–006–1 through the Reliability Standards development process that ensures that the reliability coordinator, which is the highest level of authority responsible for reliability of the Bulk-Power System, is involved in the development and approval of system restoration plans.

g. Establish, Maintain, and Document a Regional Blackstart Capability Plan (EOP–007–0)

640. EOP–007–0, which deals with establishing, maintaining and documenting regional blackstart capability plans, ensures that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in the overall coordinated regional system restoration plans.

641. The NOPR did not propose to approve or remand EOP–007–0, because it applies only to regional reliability organizations.

i. Comments

642. APPA agrees that EOP–007–0 should not be approved as a mandatory Reliability Standard and states that in the interim the regional reliability organizations and Regional Entities should continue to perform this function. In addition, APPA proposes that, in the interim, an umbrella organization composed of representatives from each regional reliability organization and Regional Entity should be formed to establish operation planning rules, including blackstart requirements, across the Eastern Interconnection. APPA suggests that such an effort would go a long way in identifying critical facilities, using consistent and transparent study assumptions and minimizing seams during system emergencies throughout the Interconnection.

643. TANC states that the number of blackstart units and their locations depend heavily on regional characteristics and cannot be prescribed in a uniform, continent-wide manner. It proposes that regional flexibility be afforded to provide an appropriate mix of facilities to achieve the reliability objectives. EEI suggests that EOP–007–0 be rewritten so that compliance obligations are assigned directly to those entities that provide the data and other information.

644. FirstEnergy and MRO state that the reliability coordinator, not the Regional Entity, should be responsible for the regional blackstart plan for its area of responsibility. Further, FirstEnergy states that the blackstart plan developed for a region should be consistent with NRC requirements, should recognize that nuclear units have no blackstart capability and should recognize that nuclear units must have priority access to off-site power for safety reasons. FirstEnergy requests that the Commission direct NERC to revise the definition of a blackstart unit to mean a ''diesel, hydro, pump storage, or the combustion turbine generating unit that is used to provide cranking power to a larger steam generating unit designed to restore load'' or to mean a ''larger steam generating unit designed to restore load.'' [254] MRO states that arrangements for coordination of blackstart capability should be addressed in a contract between appropriate entities.

ii. Commission Determination

645. The Commission will not approve or remand EOP–007–0, because it applies only to regional reliability organizations. However, the Commission provides guidance for the ERO's future consideration.

646. The Commission disagrees with APPA that an umbrella organization is needed for the Eastern Interconnection while the Reliability Standard is pending final approval. The Commission is persuaded that FirstEnergy's and MRO's comments concerning the reliability coordinator being responsible for regional blackstart plans have merit. The Commission has directed that the reliability coordinator approve the system restoration plans and this is a logical extension of that direction. However, until such time as the Reliability Standard has been revised and approved by the ERO and the Commission, the regional reliability organization (or Regional Entity, depending on the organization of a particular region) should continue to perform this role as it has in the past.[255]

647. With regard to TANC's request for regional flexibility in determining the appropriate mix of facilities needed to achieve the reliability objectives, it is

[254] *See* FirstEnergy at 35.

[255] *See* NOPR at P 328.

our understanding that the Reliability Standard provides for the number and location of blackstart units to vary depending on the specific requirements of each system. We believe that uniformity will be required, however, in the criteria used to determine the number and location of blackstart units and testing requirements.

648. EEI, FirstEnergy and MRO offer suggestions for improving the Reliability Standard. The Commission directs the ERO to consider these suggestions in future revisions to improve EOP–007–0, through the Reliability Standards development process.

649. Accordingly, the Commission will not approve or remand EOP–007–0 at this time.

h. Plans for Loss of Control Center Functionality (EOP–008–0)

650. EOP–008–0 addresses plans for loss of control center functionality. It requires each reliability coordinator, transmission operator and balancing authority to have a plan to continue reliable operations and to maintain situational awareness in the event its control center is no longer operable.

651. The Commission proposed five modifications to the Reliability Standard and requested additional comments on other issues. We have grouped the comments into two general categories: (1) Capabilities of backup control centers and (2) which entities should have full backup centers. Below, we address each topic separately, followed by an overall conclusion and summary.

i. Capabilities of Backup Control Centers

652. In the NOPR, the Commission proposed to approve Reliability Standard EOP–008–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to EOP–008–0 that includes a Requirement that provides for backup capabilities that, at a minimum, must: (1) Be independent of the primary control center; (2) be capable of operating for a prolonged period of time and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.[256] In addition to these three capabilities requirements, the Commission solicited comments concerning other specific capabilities.

(a) Comments

653. EEI, Entergy, FirstEnergy and Northern Indiana support the proposed modifications to EOP–008–0. Entergy agrees with the Commission's proposed modifications to include more Requirements regarding backup capabilities.

654. APPA, Nevada Companies and TAPS caution that costs must be considered and compared to possible benefits. APPA states that it would take some time to implement the proposed modifications and therefore specific requirements for backup control facilities and capabilities should be left to the Reliability Standard development process. Nevada Companies cautions that utilities that have invested millions of dollars in back-up capabilities may find these facilities to be non-compliant with the proposed Reliability Standard. It suggests that cost/benefits analyses be conducted and that a grandfathering provision be adopted to protect investments in backup systems that were made in a good faith effort to comply with rules in place in the past, but which may not comply with the Reliability Standard.

655. MRO requests clarification of the term ''capability'' because it is unsure if the term is intended to refer to a facility, what such a facility should consist of and what operators should be capable of doing from that facility.

656. In response to the request for comments on backup capabilities, NERC states that these are best addressed through the Reliability Standards development process.

657. SoCal Edison suggests that a risk-based assessment be considered to determine the requirements for backup. MISO, TAPS and International Transmission note that work is underway by NERC to address the provisions for redundancy and backup control capabilities via the Operating Committee Backup Control Task Force and that the focus is on functionality rather than physical requirements. TAPS states that, rather than directing NERC to adopt specific modifications to the Reliability Standard that would inappropriately burden small systems with the cost of dual facilities, the Commission should identify objectives to the Task Force. TAPS also states that a small balancing authority might be able to meet the functional requirements for a backup control center with a contract with another entity while larger entities might need a physical backup center.

658. Northern Indiana states that the Commission's proposal appears to eliminate an entity's opportunity to contract for backup capabilities from others who already have full backup control centers. FirstEnergy and Northern Indiana advocate for flexibility in the means used to meet the backup requirements and request that the Commission clarify that a ''full backup center'' can include providing full redundancy by contract rather than physical backup center facilities. SoCal Edison states that when entities utilize the services of another entity for backup, they should be required to test the backup capability a minimum number of times during the year and that all system operators should be required to participate in such testing over a specified time period.

659. NRC suggests that this Reliability Standard require: (1) A list of the nuclear power plants and their voltage, thermal, and/or frequency limits and (2) provisions to notify nuclear power plants of the loss of control center functionality.

(b) Commission Determination

660. As we stated in the NOPR, the goal of the Reliability Standard is the continuation of reliable operations and the maintenance of situational awareness in the event that the primary control center is no longer operational.[257] Some commenters support the proposal to require backup capabilities while others including APPA, Nevada Companies and TAPS caution that the cost of the proposal may not be justified. In addition, some commenters, including FirstEnergy and Northern Indiana, advocate for flexibility in meeting the backup requirements and suggest that entities should be able to contract for full redundancy. MRO seeks clarification regarding the use of the term ''capability.''

661. In the NOPR, we found that the provision of backup capabilities should be an explicit Requirement to meet the objectives of the Reliability Standard. We chose to use the word ''capabilities'' to avoid defining particular facilities or preclude other options, including arranging for backup capabilities by contracting with others. We stated that the mechanism to provide these capabilities may include building fully redundant physical backup control centers, contracting for backup control services or using backup equipment within a separate existing facility.[258] In addition, regardless of the means used to provide the backup capabilities, as we stated in the NOPR, the time period for which backup capability is required

[256] The term ''facility'' in this context includes, but is not limited to, telecommunications, backup power supplies, computer systems and security systems. NOPR at P 335 & n.159.

[257] NOPR at P 329.

[258] *See Id.* at P 336.

should correspond to the time it would take to replace the primary control center.

662. On the issue of additional backup capabilities, NERC, MISO, TAPS and International Transmission propose that the functional requirements for backup capabilities be determined by the NERC Backup Control Task Force. NRC offers requirements it believes should be added to the Reliability Standard.

663. The Commission disagrees with the Nevada Companies' proposal for grandfathering. The Reliability Standards must define the minimum functions that are necessary for the Reliable Operation of the Bulk-Power System. The flexibility described above on how capabilities are provided should mitigate any costs incurred to upgrade older centers.

664. Given the importance to reliability of maintaining situational awareness in the event of loss of the primary control center operations, the Commission believes that, at a minimum, the three requirements—independence from the primary control center, capability to operate for a prolonged period corresponding to the time it would take to replace the primary control center, and the provision of a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center—must be included as explicit requirements in the Reliability Standard. Other additional Requirements may be developed by the Backup Control Task Force for inclusion in the Reliability Standard. The Commission directs the ERO to develop modifications to the requirements in future revisions to the Reliability Standard through the Reliability Standards development process.

ii. Which entities should have full backup centers

665. In the NOPR , the Commission proposed to direct that NERC submit a modification to EOP–008–0 that: (1) Provides that the extent of the backup capability be consistent with the impact of the loss of the entity's primary control center on the reliability of the Bulk-Power System and (2) includes a Requirement that all reliability coordinators have full backup control centers. The Commission also requested comments on what other entities, such as balancing authorities and large transmission operators, should have full backup centers.

(a) Comments

666. International Transmission, MISO and FirstEnergy state that in addition to reliability coordinators, large balancing authorities and transmission operators need full backup control centers. MISO states that there are certain situations where large generation fleets that are controlled centrally would also warrant full backup systems and that small entities can operate reliably with less robust systems. Further, it argues that the ERO needs latitude to decide from a reliability standpoint how much redundancy is needed. FirstEnergy states that in place of full backup control facilities it should be acceptable to have standing contracts in place to provide backup services in the event of a loss of a control center.

667. NERC states that the proposed directive presumes that the only way to achieve highly reliable and independent backup capability to perform reliability coordinator functions in an emergency is to have a redundant control center. NERC contends that while this may be an option, it may not be the only one for achieving the necessary reliability objective. NERC proposes that the Reliability Standard be modified to define the performance results expected rather than how an entity should meet the requirements.

668. NERC, SoCal Edison and Otter Tail state that the question of what other entities should have full backup centers is best addressed through the Reliability Standards development process. Otter Tail requests that the Commission not require all balancing authorities to have full backup centers since the loss of a small balancing authority's control center would not have a substantial impact on the reliability of the Bulk-Power System. Northern Indiana states that requiring transmission operators and balancing authorities to have full backup centers would result in significant unnecessary facility duplication, at great cost to consumers, and without a material increase in reliability.

669. FirstEnergy comments that the Reliability Standard should not require a fully redundant SCADA system for the backup control center for balancing authorities or transmission operators because the cost would be prohibitive. It states that balancing authorities, transmission operators and centrally-located generation owners should be permitted to have a single distributed computer system in place to diminish the probability of a complete system shutdown due to a natural disaster or a single man-made physical act of sabotage.

670. Nevada Companies also questions whether the significant cost of full replication could ever be cost-effective, especially considering the very high level of control center reliability achieved now with the existing solution of a single control center plus backup of critical systems.

(b) Commission Determination

671. Several commenters agree with the Commission that reliability coordinators at a minimum should have full backup control centers. They also propose that this requirement be extended to large balancing authorities, transmission operators and centrally dispatched generation facilities. Others caution on the cost implications of requiring full duplication given the very high level of control center reliability achieved with the existing technology and backup of critical systems. Having carefully considered all the issues raised by commenters and taking into account the reliability impacts of loss of primary control centers and the role of reliability coordinators as the highest level of authority responsible for reliability of the Bulk-Power System, the Commission is persuaded that all reliability coordinators must have fully redundant independent backup control centers. In response to NERC, any proposed modification that is independent from the primary center, provides for continuous monitoring and has the full functionality of the primary center would satisfy our concerns. Other entities, including balancing authorities, transmission operators and centrally dispatched generation control centers, must provide for the minimum backup capabilities discussed above but may do so through other means, such as contracting for these services instead of through dedicated backup control centers.

672. In addition, in response to FirstEnergy's concern regarding balancing authorities and transmission operators having fully redundant SCADA systems and distributed computer systems, the Commission requires the primary and backup capabilities to replicate critical reliability functionalities and be independent from the primary control center, including telemetered data and control from remote terminal units. This can be achieved through a variety of design alternatives, *e.g.*, developing a SCADA management platform that will allow telemetered data and control to be shared among SCADA systems so that data and control is not lost during a SCADA or communications failure. The Commission's focus is on function, not design.

iii. Summary of Commission Determination

673. Accordingly, the Commission approves Reliability Standard EOP–0081–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–008–0 through the Reliability Standards development process that includes a Requirement that provides for backup capabilities that, at a minimum, must: (1) Be independent of the primary control center; (2) be capable of operating for a prolonged period of time, generally defined by the time it takes to restore the primary control center; (3) provide for a minimum functionality to replicate the critical reliability functions of the primary control center; (4) provides that the extent of the backup capability be consistent with the impact of the loss of the entity's primary control center on the reliability of the Bulk-Power System; (5) includes a Requirement that all reliability coordinators have full backup control centers and (6) requires transmission operators and balancing authorities that have operational control over significant portions of generation and load to have minimum backup capabilities discussed above but may do so through contracting for these services instead of through dedicated backup control centers.

i. Documentation of Blackstart Generating Unit Tests Results (EOP–009–0)

674. Proposed Reliability Standard EOP–009–0 deals with documentation of blackstart generating unit test results. In the NOPR, the Commission proposed to approve EOP–009–0 as mandatory and enforceable without modifications.

i. Comments

675. APPA agrees that EOP–009–0 is sufficient for approval as a mandatory and enforceable Reliability Standard. Xcel states that the Reliability Standard should provide details on what constitutes a blackstart test and FirstEnergy states that EOP–009–0 should be consolidated with EOP–007–0 because the Requirements of EOP–009–0 already exist in EOP–007–0.

ii. Commission Determination

676. The Commission believes that this Reliability Standard sufficiently addresses documentation of blackstart generating unit test results. Accordingly, the Commission approves Reliability Standard EOP–009–0 as mandatory and enforceable.

677. Two commenters made suggestions for improving the Reliability Standard. The Commission directs the ERO to take these suggestions into consideration when revising the Reliability Standard through the Reliability Standards development process.

5. FAC: Facilities Design, Connections, Maintenance, and Transfer Capabilities

678. The nine Facility (FAC) Reliability Standards address topics such as facility connection requirements, facility ratings, system operating limits and transfer capabilities. The FAC Reliability Standards also establish requirements for maintaining equipment and rights-of-way, including vegetation management. The NOPR provided direction for seven of the nine FAC Reliability Standards; NERC withdrew two others, Reliability Standards FAC–004–0 and FAC–005–0. NERC, in its November 15, 2006 filing requests approval of three additional FAC Reliability Standards: FAC–010–0, FAC–011–0 and FAC–014–0. These Reliability Standards are being addressed in a separate docket.

a. Facility Connection Requirements (FAC–001–0)

679. Proposed Reliability Standard FAC–001–0 is intended to ensure that transmission owners establish facility connection and performance requirements to avoid adverse impacts to the Bulk-Power System. In the NOPR, the Commission proposed to approve FAC–001–0 as mandatory and enforceable.

i. Comments

680. APPA agrees with the Commission's proposal to approve FAC–001–0 as mandatory and enforceable.

ii. Commission Determination

681. As discussed in the NOPR, the Commission believes that Reliability Standard FAC–001–0 is just, reasonable, not unduly discriminatory or preferential and in the public interest and approves it as mandatory and enforceable.

b. Coordination of Plans for New Generation, Transmission, and End-User Facilities (FAC–002–0)

682. Proposed Reliability Standard FAC–002–0 requires that each generation owner, transmission owner, distribution provider, LSE, transmission planner and planning authority assess the impact of integrating generation, transmission and end-user facilities into the interconnected transmission system.

683. In the NOPR, the Commission proposed to approve Reliability Standard FAC–002–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to FAC–002–0 that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL–001 through TPL–003.

i. Applicability and Assessment Responsibility

(a) Comments

684. APPA, Xcel and FirstEnergy state that this Reliability Standard is not clear about who will perform the required assessment and how many assessments are required under this Reliability Standard. APPA requests that the Reliability Standard be clarified to state that the required assessment must be performed only by the transmission planner and the planning authority. Xcel requests that the Commission clarify that only one required assessment needs to be done when new facilities are added, and that all the listed entities should participate in that single assessment.

685. FirstEnergy requests that NERC clarify what is considered a new facility and asks if, for example, up-rates should be included as new facilities. MRO is concerned that the impact of the Commission's directive is too broad and may have a substantial affect on those individual entities that are responsible for performing the studies; MRO asks the Commission to clarify FAC–002–0 to the extent necessary, but does not propose a specific change.

686. Six Cities requests that this Reliability Standard clarify that all applicable entities must make available data necessary for all other responsible entities to perform the required assessment. Six Cities also suggests that the transmission operator be added as an entity to which this Reliability Standard is applicable, at least from the perspective that it make necessary data available to all other entities responsible for assessment. TAPS believes that this Reliability Standard seems to assume that the LSE and distribution provider actively participate in planning of new facilities in the Bulk-Power System. TAPS states that very few LSEs or distribution providers have the expertise to perform the tasks outlined in this Reliability Standard and that these two entities provide only certain

data regarding certain new facilities to some or all of the other entities identified in this Reliability Standard. TAPS therefore believes that it would be unreasonable to require LSEs to provide the transmission planning evaluations and assessments called for by R1. California Cogeneration believes that the Reliability Standard implies that generator owners will perform an independent assessment and if so, it believes that such task is impossible, since generators do not have the relevant information about the power system to perform such evaluations. California Cogeneration believes that the Reliability Standard should be clarified so that generator owners cooperate with and provide input to the assessment performed by the transmission operator and the balancing authority.

687. FirstEnergy states that both MISO and PJM already have Large Generator Interconnection Procedures (LGIP) in place that provide a formal process that meets the requirements listed under R1, and asks that the Commission state that complying with the interconnection agreement and/or OATT satisfies this requirement. MISO states that their procedures for coordinating plans for new generation, transmission and end-user facilities includes modeling of normal system and contingency conditions.

(b) Commission Determination

688. All of the above commenters request clarification of Requirement R1 in the Reliability Standard that states that various functional entities ''shall each coordinate and cooperate on its assessments with its transmission planner and planning authority.'' [259] The Commission believes that all entities listed in the Applicability section have a stake in the performance of the system and should have the opportunity to provide input in the assessment under R1. The Commission believes that commenters have raised valid concerns that, if addressed, would make the Reliability Standard better. The wording would allow a number of organizational approaches to achieving the goal of performing an analysis. The Commission does not intend to limit which organizational approach is used by the entities, only to assure that a single competent and collaborative analysis is performed. Therefore, the Commission directs the ERO to address these concerns in the Reliability Standards development process.

689. FirstEnergy asks the Commission to state that complying with MISO's and PJM's interconnection agreements and/or OATT satisfies requirement R1 under this Reliability Standard. We will not make that determination here. If FirstEnergy believes that complying with the MISO and PJM interconnection procedures meets the applicable Reliability Standards, then it should follow those procedures, it should not be concerned about violating the Reliability Standard.

ii. Standards of Conduct

(a) Comments

690. Xcel and MidAmerican believe that the assessment required under this Reliability Standard may conflict with the Commission's Standards of Conduct [260] since the assessment requires coordination among several different functional groups within a vertically integrated public utility. MidAmerican asserts that, since direct communication between the generation and transmission entities would result in more efficient overall planning, the Commission should clarify its intended application of Standards of Conduct restrictions on joint planning activities. Xcel asks the Commission to clarify that actions taken to comply with this Reliability Standard will not result in a transmission provider being in violation of the Standards of Conduct.

(b) Commission Determination

691. The Commission disagrees with MidAmerican and Xcel that this Reliability Standard may conflict with the Standards of Conduct. This type of system assessment is being performed today with the cooperation of the entities listed in the Applicability section. Further, we note that the Standards of Conduct were designed to address such interactions. The entities participating in the assessment effort can continue to contribute to this assessment and observe the Standards of Conduct at the same time. If any entity finds an area where it believes the Standards of Conduct prevent it from cooperating with the assessment process, it may seek clarification from the Commission as to whether that area of involvement is in conflict with the Standards of Conduct.

iii. Reference to TPL Reliability Standards

(a) Comments

692. While APPA and EEI agree with the Commission's proposal to direct NERC to submit a modification to FAC–002–0 that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL–001–0 through TPL–003–0, Entergy disagrees and proposes that evaluation of system performance under Reliability Standards TPL–001–0 and TPL–002–0 should be sufficient. Entergy states that given the large number of small end-user requests that transmission operators may receive, expanding the scope of Requirement R1.4 may lead to additional work and documentation that ultimately will not benefit reliability. First Entergy states that the proposed reference to TPL Reliability Standards should be expanded to include TPL–001–0 through TPL–004–0.

(b) Commission Determination

693. The Commission notes that APPA and EEI agree with the Commission's proposed directive to NERC to modify FAC–002–0 to require evaluation of system performance under both normal and contingency conditions by referencing TPL–001–0 through TPL–003–0. The Commission also notes that NERC, in response to the Staff Preliminary Assessment, has also agreed with the same proposal.[261] These three TPL Reliability Standards cover normal operation, first contingency operation and multiple contingency operations respectively. The Commission disagrees with Entergy that TPL–001–0 and TPL–002–0 are sufficient because it is important to plan for new facilities taking into account not only normal circumstances but also contingencies. In addition, we note that including TPL–001–0 through TPL–003–0 will result in the FAC–002 Reliability Standard being consistent with Order No. 2003, which requires interconnecting entities to take into account multiple contingencies in interconnection studies. With respect to FirstEnergy's suggestion to also include a reference to Reliability Standard TPL–004–0, we direct the ERO to consider it through the Reliability Standards development process.

694. Accordingly, the Commission approves Reliability Standard FAC–002–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC–002–0 through the Reliability Standards development process that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL–001 through TPL–003.

[259] FAC–002–0.

[260] *Standards of Conduct for Transmission Providers*, Order No. 2004, FERC Stats. & Regs., Regulations Preambles ¶ 31,155 (2003), *order on reh'g*, Order No. 2004–A, III FERC Stats. & Regs. ¶ 31,161 (2004), *order on reh'g*, Order No. 2004–B, III FERC Stats & Regs. ¶ 31,166 (2004).

[261] NOPR at P 352.

Further, the Commission also directs the ERO to consider the above commenters' concerns through the Reliability Standards development process.

c. Transmission Vegetation Management Program (FAC–003–1)

695. According to NERC, FAC–003–1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way by maintaining safe clearances between transmission lines and vegetation, and establishing a system for uniform reporting of vegetation-related transmission outages. FAC–003–1 would apply to transmission lines operated at 200 kV or higher voltage (and lower-voltage transmission lines which have been deemed critical to reliability by a regional reliability organization). It would require each transmission owner to have a documented vegetation management program in place, including records of its implementation. Each program must be designed for the geographical area and specific design configurations of the transmission owner's system.

696. This Reliability Standard requires a transmission owner to define a schedule for and the type (aerial or ground) of right-of-way vegetation inspections. In addition, it requires a transmission owner to determine and document the minimum allowable clearance between energized conductors and vegetation before the next trimming, and it specifically provides that ''Transmission-Owner-specific minimum clearance distances shall be no less than those set forth in the IEEE Standard 516–2003 (IEEE Guide for Maintenance Methods on Energized Power Lines).'' [262]

697. In the NOPR, the Commission proposed to approve Reliability Standard FAC–003–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to FAC–003–1 that: (1) Requires the ERO develop a minimum vegetation inspection cycle that allows variation for physical differences and (2) removes the general limitation on applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO.

[262] FAC–003–1 (Requirement R1.2.2).

i. Applicability

(a) Comments

698. Entergy agrees with the Commission's proposal and supports applying the Reliability Standard to only those lines that have an impact on reliability as determined by the ERO, as supported by reliability studies using consistent reliability contingency criteria.

699. LPPC supports using an impact-based definition of the Bulk-Power System to determine applicability and suggests that the definition of significant adverse impact should be determined through the NERC process. Further, LPPC asserts that actual facilities meeting that criteria should be determined by Regional Entities, which best understand the impacts of facilities on the regional system. LPPC notes that Regional Entities can continue to use such tools as modeling and power flow analyses to determine which facilities are critical to the reliability of the Bulk-Power System.

700. APPA and Avista believe that Regional Entities should determine what transmission facilities this standard applies to, since Regional Entities have detailed knowledge regarding the transmission facilities within their regions. APPA would have the Regional Entities create a regional Reliability Standard to do so, subject to ERO review for reasonableness and consistency. Avista points out that WECC and the other Regional Entities have already reviewed and designated critical lower voltage transmission facilities, and the Reliability Standards currently apply to such facilities.

701. MISO asks for clarification with respect to the intent of adding transmission lines below 200 kV ''that impact reliability'' and whether the included lines are IROL-related facilities [263] or some other facilities. Progress and SERC suggest that it may be appropriate to limit the applicability of the Reliability Standard to all lines that are operated at 200 kV and above and to operationally significant circuits between 100 kV and 200 kV that are elements of IROLs.

702. California PUC believes that discretion about determining which lines are critical to the Bulk-Power System should be left to the individual state (working in concert with RTOs and ISOs), which has much greater knowledge of what is needed on the local level, rather than to NERC or the Regional Reliability Organization.

[263] An IROL-related facility is a facility whose outage would result in an Interconnection Reliability Operating Limit (IROL) violation.

703. Progress, SERC, FirstEnergy and Avista argue that automatically subjecting lines below 200 kV to Reliability Standard FAC–003–1 would increase maintenance, documentation and reporting costs and impacts to land owners, but would not necessarily increase the reliability of the grid. LPPC does not object to eliminating the 200 kV bright line threshold, but believes that extending vegetation management practices to all facilities of 100 kV and above would unnecessarily extend the scope of the vegetation management requirements, creating large cost increases for many utilities without creating a material increase in the reliability of the Bulk-Power System. FirstEnergy recommends that if the voltage level is lowered, implementation, especially for reporting requirements, should be spread over at least one year. Similarly, Xcel asks the Commission to allow flexibility in complying with this Reliability Standard for lower-voltage facilities that previously were not subject to this Reliability Standard.

704. EEI maintains that not changing this Reliability Standard would best maintain reliability, since removing the existing 200 kV threshold requirement could inadvertently expose the Bulk-Power System to a new set of risks. SoCal Edison argues that the Reliability Standard already covers transmission lines rated less than 200 kV, because Requirement 4.3 of FAC–003–1 states that this Reliability Standard ''shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the regional reliability organization as critical to the reliability of the electric system in the region.''

705. APPA opposes the Commission's proposal to direct NERC to change the applicability of this Reliability Standard. APPA argues that the Commission should deal with this concern by having NERC reevaluate the Reliability Standard. National Grid argues that expanding the applicability of Reliability Standards would not be appropriate because it could dramatically change the meaning of the Reliability Standards and would undermine the Reliability Standard development process which yielded the careful balances struck in developing the standards.

706. NERC argues that the Commission's proposed modification should be vetted through the Reliability Standards development process to better understand what will be gained in terms of impacts to the reliability of the Bulk-Power System. NERC notes that the current applicability of the Reliability

Standard to 200 kV and above transmission lines was debated extensively by the industry, and any change to this requirement should be vetted again.

(b) Commission Determination

707. We will not direct NERC to submit a modification to the general limitation on applicability as proposed in the NOPR. However, we will require the ERO to address the proposed modification through its Reliability Standards development process. As explained in the NOPR, the Commission is concerned that the bright-line applicability threshold of 200 kV will exclude a significant number of transmission lines that could impact Bulk-Power System reliability. Although the regional reliability organizations are given discretion to designate lower voltage lines under the proposed Reliability Standard, none have designated any operationally significant lines even though there are lower voltage lines involving IROL as suggested by Progress and SERC. We continue to be concerned that this approach will not prospectively result in the inclusion of all transmission lines that could impact Bulk-Power System reliability. In proposing to require the ERO to modify the Reliability Standard to apply to Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO, we did not intend to make this Reliability Standard applicable to fewer facilities than it currently is with the 200 kV bright line applicability, but to extend the applicability to lower-voltage facilities that have an impact on reliability. We support the suggestions by Progress Energy, SERC and MISO to limit applicability to lower voltage lines associated with IROL and these suggestions should be part of the input to the Reliability Standards development process. Similarly, the ERO should evaluate the suggestions proposed by LPPC, APPA and Avista.

708. California PUC suggests that states should have discretion over what lines are critical to Bulk-Power System reliability. The Commission has been given the responsibility to approve Reliability Standards that assure the Reliable Operation of the Bulk-Power System, including which facilities are covered by the Reliability Standards. We cannot delegate that responsibility as proposed by California PUC. Further, since many transmission facilities traverse multiple states, we are concerned that this proposal could result in the Reliability Standard applying to a section of a line in one state but not applying to the same line in a neighboring state. Since a vegetation-related outage affects all customers connected to that transmission line, customers in both states could potentially have lower reliability as a result of one state having a less stringent standard than another.

709. Avista, LPPC, Progress and SERC raise concerns about the cost of implementing this Reliability Standard if the applicability is expanded to lower-voltage facilities. We recognize these concerns, and this was one of the reasons we proposed to apply this Reliability Standard to Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO. We recognize that many commenters would like a more precise definition for the applicability of this Reliability Standard, and we direct the ERO to develop an acceptable definition that covers facilities that impact reliability but balances extending the applicability of this standard against unreasonably increasing the burden on transmission owners.

710. FirstEnergy and Xcel suggest that if the applicability of this Reliability Standard is expanded, the Commission should allow flexibility in complying with this Reliability Standard for lower-voltage facilities, or allow lower-voltage facilities one year before the Reliability Standard is implemented. The ERO should consider these comments when determining when it would request that the modification of this Reliability Standard to go into effect.

711. In response to EEI's concerns that removing the existing 200 kV threshold could expose the Bulk-Power System to a new set of risks, we clarify that we are not immediately modifying this Reliability Standard. Instead, it will go into effect as written and the ERO will revise it through the Reliability Standards development process, with the expectation that the applicability of this Reliability Standard will expand to include additional facilities that impact reliability that currently are not covered by this Reliability Standard. A modification that reduces the applicability of this Reliability Standard would not meet the Commission's directives. In response to SoCal Edison's argument that the Reliability Standard already addresses the Commission's concerns, the Commission agrees that while there appears to be a mechanism for inclusion of additional lines, none have been included. This lack of inclusion is in spite of the evidence that some lower voltage lines can have significant impacts on the Bulk-Power System, including IROLs and SOLs.

712. In response to APPA, NRECA and NERC we agree that the proposed modifications should be vetted through the Reliability Standards development process. The Commission's goal is to promote the Reliable Operation of the Bulk-Power System by including all of those entities necessary to comply with this Reliability Standard. We believe that requiring the Reliability Standard to include a greater number of entities and exclude those that will not affect reliability will more effectively sustain reliability than an overly exclusive list of applicable entities.

ii. Inspection Cycles

713. In the NOPR, the Commission proposed to direct NERC to submit a modification to FAC–003–1 that requires the ERO to develop a minimum vegetation inspection cycle that allows variation for physical differences.

(a) Comments

714. FirstEnergy states that a designation of a minimum annual inspection cycle is appropriate and the method of inspection (aerial or by ground) should be left to the transmission owner. Dominion cautions that if there is a requirement for annual inspections, it should be flexible and allow for different approaches to transmission line inspections.

715. APPA, Entergy, EEI, LPPC, Progress Energy, SERC and SoCal Edison disagree with the Commission's proposal to require the ERO to set minimum vegetation inspection cycles that allow for physical differences. APPA, Entergy and LPPC say that, instead of proposing the development of a Reliability Standard for minimum vegetation inspection cycles, the Commission should permit the transmission system owner or local utility to determine the inspection cycle best suited for its system and adhere to that cycle, with compliance enforcement performed by the Regional Entities and the ERO.

716. Progress Energy and SERC believe that the Reliability Standard as written provides flexibility regarding vegetation inspection cycles and that the Commission should not impose requirements on the ERO to develop minimum inspection intervals on a continent with such regional diversity in climate and vegetation. In addition, Progress Energy argues that, where a particular region is heavily forested and has heavy rainfall along with extended or year round growing seasons, a ''back stop'' minimum inspection frequency could lead transmission owners to conduct inspections less frequently than what the local conditions require, which would lead to a lowest common denominator Reliability Standard. This

could result in a transmission owner complying with the Reliability Standard while not adequately protecting the reliability of that region's transmission system.

717. Progress Energy and SERC argue that, since the performance metrics in FAC–003–1 require reporting of applicable transmission interruptions caused by vegetation, the compliance process associated with this Reliability Standard should appropriately identify transmission owners' inspection cycles that are not adequate, and the ERO can use its authority to remedy any vegetation-related outage that is attributed to the transmission owner's inspection frequency.

718. SoCal Edison states that transmission owners are already obligated by Requirement R1.1 to establish a minimum vegetation inspection schedule that allows adjustment for changing conditions. SoCal Edison believes that the best measure of an effective transmission vegetation management program is whether or not tree-to-line contacts are occurring. SoCal Edison recommends the Commission rescind the two proposed directives and order no further revisions to FAC–003–1 until such time as Reliability Standard is deemed unenforceable by the ERO or is not otherwise achieving its stated goals.

719. APPA and Progress Energy state that a minimum vegetation inspection cycle could result in an undue financial burden for some regions of the country, because they would be forced into a minimum cycle that might be inappropriate for their own region. For example, Progress Energy states that, where a particular region is arid, sparsely forested or has a minimum growing season, a ''back stop'' minimum could require a more frequent interval than is realistically needed. This would result in increased and unnecessary costs to the transmission owner and its customers without providing a comparable increase in reliability. EEI believes that a minimum inspection cycle will add nothing to the strength of the existing practices and could add a requirement that is not merited by actual circumstances in many locations.

(b) Commission Determination

720. The Commission is concerned about minimizing outages and supports a realistic inspection cycle. In the NOPR, the Commission proposed a minimum inspection cycle that takes account of physical differences as one way to address this concern. However, we recognize that there may be other options to achieve the same reliability goal. For example, the ERO could determine whether a prepared company-tailored inspection cycle is appropriate given the physical and geographic factors and, through audits, inspect individual vegetation management programs for compliance.

721. While the Commission disagrees that incorporating a backstop would lead to a lowest common denominator Reliability Standard, the Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time. Instead, the Commission agrees that an entity's vegetation management program should be tailored to anticipated growth in the region and take into account other environmental factors. The goal is to assure that transmission owners conduct inspections at reasonable intervals. In the Commission's Vegetation Management Report, we found that many entities performed aerial or ground inspections less than every three years or even ''as needed.'' [264]

722. The Commission continues to be concerned with leaving complete discretion to the transmission owners in determining inspection cycles, which limits the effectiveness of the Reliability Standard. Accordingly, the Commission directs the ERO to develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors. These inspection cycles are to be used in compliance auditing of FAC–003–1 by the ERO or Regional Entity to ensure such inspection cycles and vegetation management requirements are properly met by the responsible entities.

iii. Minimum Clearances on National Forest Service Lands

723. In the NOPR, the Commission did not propose to modify the ERO's general approach with respect to clearances. However, the Commission expressed its belief that any potential issues regarding minimum clearances on National Forest Service (Forest Service) lands should be dealt with on a case-by-case basis. The Commission requested comments on whether another approach would be more appropriate to address this issue.

(a) Comments

724. APPA believes that a case-by-case approach may have to be employed, since Forest Service lands are located all across the country and have different regional characteristics. APPA notes that U.S. Fish and Wildlife Service personnel have begun to take action regarding vegetation management on non-federal lands, and reports that APPA members have been told by U.S. Fish and Wildlife personnel to refrain from cutting vegetation at certain times of the year in the absence of an imminent reliability threat. APPA concludes that this information conflicts with specifying minimum nationwide vegetation inspection/cutting cycles and clearances. In addition, APPA requests clarification of the Commission interpretation ''we interpret the FAC–003–1 to require trimming that is sufficient to prevent outages due to vegetation management practices under all applicable conditions.''

725. Several commenters express concern about the Commission's position that any potential issues regarding minimum clearances on National Forest Service lands should be dealt with on a case-by-case basis.[265] EEI, Progress Energy and SERC believe that this approach is inconsistent with the Reliability Standard's intent to use consistent approaches in setting minimum vegetation clearance distances on both private and public lands and the Commission's statement that this Reliability Standard requires minimum clearances that are ''sufficient to prevent outages due to vegetation management practices under all applicable conditions.'' [266] Therefore, International Transmission, EEI, LPPC, Progress Energy and SERC assert that Reliability Standard FAC–003–1 should be applicable to all responsible entities including those with transmission on both private and public lands because consistency is the only way to provide a uniform and reliable electrical system. Dominion suggests the Commission defer to NERC and the stakeholder process to develop specifications for clearances.

726. Progress Energy and SERC note that EEI and certain federal agencies [267] have jointly addressed the issue of consistency in vegetation management work on federal lands, and developed a memorandum of understanding (Vegetation MOU) which sets the framework for managing vegetation on transmission line rights-of-way under

[264] Utility Vegetation Management and Bulk Electric Reliability Report at 10–11, available at *http://www.ferc.gov/industries/electric/indus-act/reliability/2004.asp* (Vegetation Management Report).

[265] *See, e.g.*, EEI, Energy, International Transmission, Progress Energy, SERC, LPPC and MISO.

[266] The NOPR states that ''Accordingly, we interpret the FAC–003–1 to require trimming that is sufficient to prevent outages due to vegetation management practices under all applicable conditions* * *'' NOPR at P 380.

[267] Forest Service, Bureau of Land Management, Fish & Wildlife Service, National Park Service, and U.S. Environmental Protection Agency.

Federal agency jurisdiction.[268] Progress Energy and SERC recommend using the EEI's Vegetation MOU framework for managing vegetation on transmission line rights-of-way under federal agency jurisdiction rather than the case-by-case approach proposed in the NOPR. LPPC recommends creating a bright-line when it comes to utilities' obligations (and rights) for trimming vegetation located on Forest Service lands. Avista and Portland General ask that the Vegetation MOU be affirmed by the Commission and permitted to govern transmission line rights-of-ways located on lands managed by federal land management agencies.

727. SoCal Edison believes that transmission owners should be allowed the latitude to establish measures/procedures for less rigid tree-to-line clearances in response to state and federal agency demands or requests but is concerned that these measures/procedures will prove to be of little or no value in the event of an ERO investigation into a tree-to-line contact occurring within national/state forestry boundaries or on private property.

728. California PUC points out that California already has requirements applicable to minimum vegetation clearance, and that the Commission must take care to assure that any mandatory Reliability Standard does not preempt the ability of California (and other states with similar state standards) to impose stricter requirements that have no adverse impacts on reliability.

729. FirstEnergy states that the standard should define rights-of-way to encompass the required clearance area instead of the corresponding legal land rights. Some rights-of-way may be larger to accommodate future needs and therefore may exceed clearances needed for existing lines. FirstEnergy believes that Reliability Standards should not require clearing entire rights-of-way when the required clearance for existing lines does not take up the entire right-of-way.

(b) Commission Determination

730. As proposed in the NOPR, the Commission approves Reliability Standard FAC–003–1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC–003–1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions. As to APPA's requests for clarification concerning the term ''under all applicable conditions,'' the Reliability Standard already addresses this issue in Requirement R3.2 by allowing for exceptions for natural disasters (including wind shears and major storms) that cause vegetation to fall into the transmission lines from outside the ROW. The Commission therefore finds that no clarification is required in response to APPA.

731. The Commission agrees that ownership of the land does not change the impact of a vegetation-related outage on the Bulk-Power System. However, the present Reliability Standard leaves the determination and documentation of ''clearance 1'' to transmission owners. As such, there are no specific clearances, or criteria/procedures to develop clearances, before the Commission for approval. What is in front of the Commission relative to ''locations on the right-of-way where the Transmission Owner is restricted from attaining the clearances specified in Requirement R1.2.1'' is addressed in Requirement R1.4. Requirement R1.4 states that ''Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the right-of-way where the Transmission Owner is restricted from attaining the clearances specified in Requirement R1.2.1.'' This Requirement addresses the instances when an entity cannot attain the clearances that it needs on land that it controls. Since there are multiple mitigation measures that the entity can employ to achieve the goal of preventing outages due to vegetation management practices, the Commission has stated that any potential issues regarding minimum clearances on Forest Service lands should be dealt with on a case-by-case basis.

732. Avista and Portland General ask the Commission to endorse the Vegetation MOU. The Commission reiterates its direction that the minimum clearances must be sufficient to avoid any sustained vegetation-related outages for all applicable conditions. The Vegetation MOU references IEEE 516 as the only way to determine applicable minimum clearances. The Commission declines to endorse the use of IEEE 516 as the only minimum clearance because it is intended for use as a guide by highly-trained maintenance personnel to carry out live-line work using specialized tools under controlled environments and operating conditions, not for those conditions necessary to safely carry out vegetation management practices.[269] Further, the allowable clearances in the IEEE standard are significantly lower than those specified by the relevant U.S. safety codes. As such, use of IEEE clearance provision as a basis for minimum clearance prior to the next tree trimming as a Requirement in vegetation management is not appropriate for safety and reliability reasons. For example, the IEEE Standard 516–2003 specifies a 2.45-foot clearance from a live conductor for the 120 kV voltage class,[270] whereas the ANSI Z–133 standard specifies 12 feet, 4 inches as the approach distance for the 115 kV voltage class.[271]

733. Accordingly, the Commission directs the ERO to develop a Reliability Standard that defines the minimum clearance needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land. While this consensus is developed, the Commission directs the ERO to address any potential issues regarding mitigation measures needed to assure these minimum clearances on Forest Service lands are appropriate on a case-by-case basis. The Commission also directs the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results of this analysis and information to develop a Reliability Standard that would apply to transmission lines crossing both federal and non-federal land.

734. In regard to California PUC's concern about its ability to impose stricter requirements on vegetation clearances, the Commission notes that section 215(i)(3) of the FPA states that nothing in section 215 shall be construed to preempt the authority of a state to take action to ensure the reliability of electric service within that state, as long as the action is not inconsistent with any Reliability Standard. Therefore, the State of California may set its own vegetation management requirements that are stricter than those set by the Commission as long as they do not conflict with those set by the Commission. Further, the Commission notes that once a Reliability Standard is established, California PUC can develop stricter rules to be applied within the

[268] The Vegetation MOU is available at *http://www.eei.org/industry_issues/environment/land/vegetation_management/EEI_MOU_FINAL_5-25-06.pdf.*

[269] Controlled environments and operating conditions include clear days without precipitation, high winds or lightning.

[270] Institute of Electrical and Electronics Engineers, Inc. (IEEE) Standard 516–2003, IEEE Guide for Maintenance Methods at 20.

[271] ANSI Z133, American National Standards Institute Standard for Tree Care Operations—Pruning, Trimming, Repairing, Maintaining and Removing Trees, and Cutting Brush—Safety Requirements.

state of California, and if it wants them to be enforceable under section 215 of the FPA, could submit those Reliability Standards to the ERO and the Commission for approval as a regional difference.

735. FirstEnergy suggests that rights-of-way be defined to encompass the required clearance areas instead of the corresponding legal rights, and that the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way. The Commission believes this suggestion is reasonable and should be addressed by the ERO. Accordingly, the Commission directs the ERO to address this suggestion in the Reliability Standards development process.

iv. Summary of Commission Determinations

736. The Commission approves FAC–003–1 as mandatory as enforceable. In addition, while we do not direct the ERO to submit a modification to the general limitation on applicability as proposed in the NOPR, we require the ERO to address the proposed modification through its Reliability Standards development process as discussed above. Further, while the Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time, it directs the ERO to develop compliance audit procedures to identify appropriate inspection cycles based on local factors. These inspection cycles are to be used in compliance auditing of FAC–003–1 by the ERO or Regional Entity to ensure such inspection cycles and vegetation management requirements are properly met by the responsible entities. Finally, the Commission directs the ERO to develop a Reliability Standard through the Reliability Standard development process that defines the minimum clearance needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land. While this consensus is developed, the Commission directs the ERO to address any potential issues regarding mitigation measures needed to assure these minimum clearances on Forest Service lands are appropriate on a case-by-case basis. The Commission also directs the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results of this analysis and information to develop a Reliability Standard that would apply to transmission lines crossing both federal and non-federal land.

d. Facility Ratings Methodology (FAC–008–1)

737. FAC–008–1 requires each transmission owner and generation owner to develop a facility rating methodology for its facilities, which should consider manufacturing data, design criteria (such as IEEE, ANSI or other industry methods), ambient conditions, operating limitations and other assumptions. This methodology is to be made available to reliability coordinators, transmission operators, transmission planners and planning authorities who have responsibility in the same areas where the facilities are located for inspection and technical reviews.

738. In the NOPR, the Commission proposed to approve Reliability Standard FAC–008–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to develop a modification to FAC–008–1 through the Reliability Standards development process that requires transmission and generation facility owners to: (1) Document underlying assumptions and methods used to determine normal and emergency facility ratings; (2) develop facility ratings consistent with industry standards developed through an open process such as IEEE or CIGRE and (3) identify the limiting component(s) and define the increase in rating based on the next limiting component(s) for all critical facilities.

i. Methodology Used To Determine Facility Ratings and Documentation of Underlying Assumptions

(a) Comments

739. EEI, Valley Group, MidAmerican and TANC support the Commission's proposal to require additional documentation as a reasonable means to provide more transparency and consistency. EEI suggests that this requirement could be accommodated with a provision for the disclosure of such information upon request by a registered user, owner or operator. TANC supports the Commission's proposal to not require a uniform facility rating methodology and recommends that the Commission adopt a policy that provides for each transmission owner and generation owner to develop and document a facility rating methodology, which is consistent with industry methodologies, for their facilities. TANC also states that the methodology used for developing facility ratings should include a description of and justification for all of the assumptions. Valley Group states that it is extremely important that the underlying assumptions and methods are documented and known to all parties. Valley Group maintains that this will also ensure that the rating assumptions used by operating and planning functions are consistent with each other. Valley Group emphasizes that making these assumptions open is important, especially regarding paths between different transmission owners, to ensure that transmission owners cannot exercise market power. It argues that open assumptions will also provide rational grounds for dispute resolution.

(b) Commission Determination

740. As EEI, TANC, Valley Group and MidAmerican discuss in their comments, the Commission's proposal to modify FAC–008–1 to require additional documentation supports the Commission's goals of improving uniformity and transparency in the facility ratings process. EEI's suggestion that having this information available for review upon request of a registered user, owner or operator should be considered by the ERO in its Reliability Standards development process. As proposed in the NOPR, the Commission directs the ERO to submit a modification to FAC–008–1 that requires transmission and generation facility owners to document underlying assumptions and methods used to determine normal and emergency facility ratings. As stated in the NOPR, the Commission believes that this added transparency will allow customers, regulators and other affected users, owners and operators of the Bulk-Power System to understand how facility owners set facility ratings through differing methods that provide equivalent results.

ii. Rating Facilities Consistent with Industry Standards Developed Through an Open Process such as IEEE and CIGRE

(a) Comments

741. The Valley Group states that the Commission correctly identifies IEEE and CIGRE as examples of open process methodologies suitable for overhead transmission line ratings calculations. It claims that IEEE and CIGRE are the only methodologies which make their algorithms available to everybody, and clearly document their assumptions. Valley Group notes that both of these methodologies will undergo a revision for accuracy regarding calculations for high temperatures and high current densities in the next two years, which may lead in some cases to slightly lower

line ratings, although the changes are not expected to be substantial.

742. APPA suggests that the proposal to rate facilities consistent with industry methodologies developed through an open process such as IEEE and CIGRE should be considered in the ERO's Reliability Standards development process rather than ordered by the Commission. LPPC asks the Commission to require only that facility ratings be consistent with good utility practice. According to LPPC, to the extent facility rating methodologies need to be more prescriptive than good utility practice, the details must be spelled out in the ERO Reliability Standards themselves, not by reference to other unspecified industry methodologies. LPPC believes that it would be poor policy for the Commission to endorse these methodologies since it would be impossible to police the processes by which such organizations develop their methodologies. MidAmerican states that the Commission should recognize that the proposal to require facility ratings be consistent with industry methodologies developed through an open process is potentially problematic, noting that certain aspects of the development of facility ratings are based on industry standards that are not developed through an open process, such as information provided by engineering textbooks or manufacturer information that is not specifically referenced in any current standard. MidAmerican recommends that the Commission delete the requirement that facility ratings be ''developed through an open process such as IEEE or CIGRE'' or add other sources that the Commission would find appropriate, such as the results of accepted scientific and engineering investigations and common sense. MRO requests that the Commission clarify whether its directive to modify FAC–008–1 to develop facility ratings consistent with industry standards developed through an open process such as IEEE or CIGRE would allow for legitimate regional differences such as climate, terrain or population density.

(b) Commission Determination

743. In the NOPR, the Commission stated, ''While not proposing to mandate a particular methodology, we do propose that the methodology chosen by a facility owner be consistent with industry standards developed through an open process such as IEEE or CIGRE.'' [272] These processes have been validated through actual testing and have been shown to provide appropriate results. Information from engineering textbooks, common sense or manufacturer information would be part of the underlying assumptions. The Commission's intent in the NOPR was to require that FAC–008–1 be modified to require that facility ratings be developed consistent with industry standards developed through an open, transparent and validated process. The Commission agrees with Valley Group that IEEE and CIGRE are two examples of such processes and disagrees with LPPC that reference to industry standards is poor policy. Industry standards that have been verified by actual testing are appropriate. However, the Commission agrees with MidAmerican that IEEE and CIGRE are just two examples of such bodies; any other open process that has been technically validated for its provision of accurate, consistent ratings is also acceptable. The ERO should consider the concerns raised by LPPC and MRO in its Reliability Standards development process, and is hereby directed to do so. The Commission does not expect there to be any regional differences because the only differences should be from different underlying assumptions that are not defined by the Reliability Standard.

iii. Identify the Limiting Component(s) and Define for All Critical Facilities the Rating Based on the Next Limiting Component Within the Same Facility

(a) Comments

744. TANC maintains that the rating information provided by the transmission owners and generator owners should include additional information about all of the limiting components of the elements (*e.g.*, transmission lines, transformers, etc.) for all critical facilities. Access to such information will enable neighboring systems to accurately study the effects of other facilities on their own systems and determine the critical elements for increasing facility ratings.

745. Valley Group states that identifying the limiting elements is an excellent objective for reliability enhancement, but notes that its granularity must be limited to major elements of the circuits, such as transformers and breakers, while treating the transmission lines as single elements. Valley Group also notes that, of the two examples discussed in the NOPR, the example regarding relay settings is technically well justified, whereas rating the line based on a single limiting span is generally impractical because line design engineers add to the National Electric Safety Code minimum requirements ''safety buffers,'' which vary depending on their confidence in the accuracy of design calculations.

746. APPA is concerned about the possible ''unintended consequences'' of this modification and questions whether this proposed Requirement can be done as a practical matter; how many critical facilities and limiting components would have to be modeled to meet such a Requirement; and whether the cost of such modeling is justified by the reliability benefits. Dynegy, MISO and Wisconsin Electric also oppose this requirement because it is ambiguous, the additional work required to identify the increase in rating based on the next limiting component(s) is unwarranted and potentially costly, and the need for any such specific information is questionable. Dynegy and Wisconsin Electric do not believe there is a widespread need for this type of information and recommend that the need for it be explored on a case-by-case basis rather than including a global requirement in the standards.

747. Dynegy, FirstEnergy and MISO state that it is not clear what specific criteria would be used to define ''critical facilities'' and ''limits.'' EEI also states that developing a practical definition of ''critical facilities'' presents a challenge, and that compliance would require the analysis of possibly hundreds of thousands of ''limiting'' transmission elements to determine whether a limit is of primary concern or is contingent on the status of other nearby elements or system conditions at a particular time. EEI suggests that, rather than requesting that the industry develop a definition, it may be more useful for the Commission to recommend that the industry develop a set of high-level criteria that could be used to identify those transmission elements that create significant potential limits that are independent of other factors and considerations.

748. EEI and TVA assert this recommendation does not seem to be intended to enhance reliability but to provide additional commercial information to the market, and may not be appropriate to include in a Reliability Standard. Portland General further points out that this information can be obtained from a transmission provider by submitting a transmission or interconnection request when ATC is not posted or not available. TVA comments that, since the focus of this proceeding is the Reliable Operation of the Bulk-Power System, changes to a proposed Reliability Standard, such as FAC–008–1, that appear designed to promote maximum commercial use of the grid are unwarranted in this

[272] NOPR at P 404.

proceeding and could jeopardize, rather than further, reliable transmission system operations.

749. MRO seeks clarification about whether the proposed modification will require that all limiting facilities elements be published. MRO believes that serious confidentiality issues are raised due to the security-sensitive nature of the information and urges the Commission not to require the publication of such information.

750. Dominion states that the Commission should exclude from this requirement facilities that are covered under an open, regional transmission expansion planning process, such as the Regional Transmission Expansion Plan process in PJM, where any interested party can be involved in the studies and determine what the limitations are and what could be done to increase transmission capacity.

751. International Transmission states that, if the Commission were to require defining the increase in facility rating based on the next limiting element, it should restrict such application to transmission elements where the conductor itself is not the limiting element. International Transmission explains that in cases where the line must be completely rebuilt, it would not be feasible to estimate the increase in facility rating, since the new line could be specified to carry virtually any amount of power.

752. MISO questions how a generator operator or generation owner would identify the increase in rating based on the next most limiting component(s) associated with generator output. FirstEnergy believes that this modification should recognize that generators may need to rely on transmission owners to point out facilities that are more limiting than the generator facilities.

753. Manitoba's technical experts disagree with the Preliminary Staff Assessment regarding FAC–008–1. The Reliability Standard properly places the responsibility of determining facility ratings with the facility owners. Manitoba also states that, since this Reliability Standard requires that the ''Facility Rating shall be equal to the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility,'' information on the next limiting component is already identified. Contrary to the Commission's view, Manitoba does not believe it would be appropriate in this Reliability Standard to identify the increase in rating for all critical facilities based on the next limiting component. In a networked system, there may be other limitations that set the current carrying capability of the critical facility.

754. Manitoba further notes that the Commission proposal may lead to international conflicts in Reliability Standards. Manitoba states that a mandated change to FAC–008–1, which forces an entity to accept facility ratings beyond its risk tolerance, would be grounds for Manitoba to recommend that the provincial government of Manitoba not approve this Reliability Standard because it would degrade reliability.

755. APPA suggests that the proposal to identify the limiting component and define for all critical facilities the rating based on the next limiting component be considered in the ERO's Reliability Standards development process rather than ordered by the Commission.

(b) Commission Determination

756. The Commission agrees with TANC that this modification would provide useful information to neighboring systems and users, owners and operators of the Bulk-Power System. The Commission also agrees with Valley Group that identifying the limiting elements of facilities enhances reliability by providing operators specific information about the limiting elements and therefore allowing them to assess the risks associated with circuit loadings.

757. In response to the comments of APPA, Dynegy, EEI, MISO and Wisconsin Electric, the Commission clarifies that this Reliability Standard and the Commission's proposed modification apply to facilities. As defined in the NERC glossary, a facility is ''a set of electrical equipment that operates as a single Bulk Electric System Element [273] (*e.g.*, a line, a generator, a shunt compensator, transformer, etc.).'' The most limiting component in a facility determines its rating, just like the rating of a chain is determined by the weakest link. The Commission's proposed modification would require identifying and documenting the limiting component for all facilities and the increase in rating if that component were no longer the most limiting component; in other words, the rating based on the second-most limiting component. The Commission further clarifies that this Reliability Standard will require this additional thermal rating information only for those facilities for which thermal ratings cause the following: (1) An IROL; (2) a limitation of TTC; (3) an impediment to generation deliverability or (4) an impediment to service to major cities or load pockets.

758. EEI and TVA raise concerns that this modification promotes commercial use of the grid rather than ensuring Reliable Operation of the Bulk-Power System, and relates more to transmission access than reliable operations. The Commission disagrees that this modification relates primarily to transmission access. When the transmission operators know which component within the transmission element is limiting they have more information to inform their decisions about how to provide for the Reliable Operation of the Bulk-Power System. Our proposed modification does not require any entity to invest in equipment to increase ratings of any facility; it simply requires the next limiting component of each facility to be identified in order to understand what components are causing the limits that are to be used in reliability mitigation assessments. The identification of the first limiting component is already an inherent requirement in the existing rating process. As clarified above, the modification to identify an increase in rating of the transmission element that would result from removing the first limitating component applies only to critical facilities whose thermal ratings have been reached causing an SOL or IROL condition. As Dominion highlights in its comments, this information is already identified in the planning processes of some RTOs and ISOs.

759. In response to the concerns raised by EEI and MRO about sharing confidential, market-sensitive information, the Commission disagrees that ratings information is confidential or market-sensitive. All users, owners and operators should have access to the facility ratings in order to operate the system reliably. Section 215(a)(4) of the FPA defines Reliable Operation, in part, as operating the elements of the Bulk-Power System within equipment and electric system thermal stability limits.[274] Without knowing the ratings, it is not possible to know whether this requirement is being met. As to the argument that this information is confidential, the Commission clarifies that, as with the other information required by this Reliability Standard, the additional information required by this modification would be shared only with users, owners and operators of the Bulk-Power System.

760. In response to Dominion's comments, if the PJM Regional Transmission Expansion Planning process meets the criteria, there is no

[273] An element is made up of one or more components.

[274] 16 U.S.C. 824o(a)(4).

need to exclude facilities covered by that process from this requirement.

761. The Commission directs the ERO to consider International Transmission's comments regarding requiring information about the increase in facility rating based on the next limiting element only for lines where the conductor itself is not the limiting element in its Reliability Standards development process. Similarly, the ERO should also consider the comments from MISO and FirstEnergy that generators will have difficulty determining the increase in ratings due to the next limiting element, since in most cases the generator itself would be the most limiting element.

762. We agree with Manitoba that this Reliability Standard properly places the responsibility to determine facility ratings on the facility owner. The Commission is not proposing to change this. We also agree with Manitoba that the most limiting component is already identified when facility ratings are determined. The Commission is only directing transmission and generation owners to provide additional information on the next limiting component within the facility so that facility ratings are more transparent.

763. In response to Manitoba's and APPA's concerns, we recognize that this is an additional requirement with some complexities, and this modification will go through the ERO Reliability Standards development process. We do not intend to usurp the Reliability Standards development process, where Manitoba may raise its concerns for the ERO to consider.

iv. Applicability to Generator Owners

(a) Comments

764. Xcel states that this Reliability Standard should not apply to generator owners because capability testing, rather than using mathematical calculations, is the preferred method of determining generating unit capability. Capability testing clearly includes the capability of all the supporting components behind the generator that are required to produce a MW of capability. Xcel also states that this proposed Reliability Standard, if applied to generating units, would not improve system reliability and could result in conflicting and confusing unit capability ratings. Xcel notes that generating units already are required to be capability-tested on a periodic and seasonal basis to demonstrate unit gross and net capability in accordance with proposed standards MOD–024–1 and MOD–025–1.

765. FirstEnergy also points out that facility ratings for nuclear units are part of NRC license agreements and that the ratings methodologies included in NRC license agreements are approved by NRC. FirstEnergy proposes that compliance with NRC ratings methodology requirements should be assumed to comply with this Reliability Standard.

(b) Commission Determination

766. The Commission agrees with Xcel that an actual test could be used as a substitute for a mathematical calculation of capability, and we ask the ERO to consider these comments in its Reliability Standards development process. The Commission understands that NRC provides ratings methodologies for nuclear power plants and not for the transmission system. Capacity ratings of nuclear generators determined using this methodology are acceptable for reliability purposes. We also direct the ERO to consider FirstEnergy's comments in its Reliability Standards development process.

v. Compliance With Blackout Report Recommendation No. 27

(a) Comments

767. Manitoba believes this Reliability Standard meets the requirement of Blackout Report Recommendation No. 27 because the recommendation does not require a uniform set of methodologies for rating facilities, but instead only recommends that there be a clear, unambiguous requirement to rate transmission lines.

768. Valley Group notes that, while the Commission's proposal would direct the ERO to respond to a part of Blackout Report Recommendation No. 27, it does not address the important second part of the Recommendation, namely dynamic ratings. Valley Group notes that dynamic ratings offer a very powerful tool both for maximizing the capabilities of transmission paths and for avoiding unnecessary transmission line loading relief. Valley Group also notes that dynamic ratings, based either on ambient-adjusted ratings or ratings generated by real-time monitoring systems, are widely used in the PJM system, while broader real-time ratings are applied on certain lines in SPP and ERCOT and at several individual utilities. Valley Group states that controlling unnecessary operator interventions with dynamic ratings both increases the reliability of Bulk-Power System and improves its economy. Valley Group concludes that it would be highly desirable for the ERO to establish policies and procedures regarding dynamic ratings—as recommended by the Blackout Report, and recommends that the Commission include such guidance in its Final Rule.

(b) Commission Determination

769. The Commission believes that implementation of the modifications discussed earlier to Reliability Standard FAC–008–1 meets our goal of implementing Blackout Report Recommendation No. 27, which is to ''develop enforceable standards for transmission line ratings.'' [275] To achieve a clear and unambiguous Requirement to rate transmission lines, it is important to understand the underlying assumptions and the methodologies that will be used to develop those ratings. The Commission recognizes that dynamic line ratings are an innovative application, and directs the ERO to consider the comments from Valley Group in future revisions of this Reliability Standard.

vi. General Comments

770. APPA notes that FAC–008–1 should be revised to replace Levels of Non-Compliance with Violation Security Levels, and to include Violation Risk Factors on all FAC–008–1 requirements.

(a) Commission Determination

771. The Commission acknowledges that the Reliability Standards are changing. In this Final Rule, we are ruling on the Reliability Standards as they were filed, and these documents use the term Levels of Non-Compliance. The ERO should address APPA's comments in its Reliability Standards development process.

vii. Summary of Commission Determination

772. Accordingly, as discussed in the responses to comments above, the Commission approves FAC–008–1 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to FAC–008–1 through its Reliability Standards development process requiring transmission and generation facility owners to: (1) Document underlying assumptions and methods used to determine normal and emergency facility ratings; (2) develop facility ratings consistent with industry standards developed through an open, transparent and validated process and (3) for each facility, identify the limiting component and, for critical facilities, the resulting increase in rating if that component is no longer limiting.

[275] Blackout Report at 162.

e. Establish and Communicate Facility Ratings (FAC–009–1)

773. FAC–009–1 requires each transmission owner and generation owner to establish facility ratings consistent with its associated facility ratings methodology and provide those ratings to its reliability coordinator, transmission operator, transmission planner and planning authority. In the NOPR, the Commission proposed to approve FAC–009–1 as mandatory and enforceable.

i. Comments

774. APPA supports approval of FAC–009–1 as a mandatory and enforceable Reliability Standard.

ii. Commission Determination

775. FAC–009–1 serves an important reliability purpose of ensuring that facility ratings are determined based on an established methodology. Further, the proposed Requirements set forth in FAC–009–1 are sufficiently clear and objective to provide guidance for compliance. Accordingly, the Commission approves Reliability Standard FAC–009–1 as mandatory and enforceable.

f. Transfer Capability Methodology (FAC–012–1)

776. Proposed Reliability Standard FAC–012–1 requires each reliability coordinator and planning authority to document the methodology used to develop its inter-regional and intra-regional transfer capabilities. This methodology must describe how it addresses transmission topology, system demand, generation dispatch and use of projected and existing commitment of transmission.

777. In the NOPR, the Commission explained that, because the methodology to calculate transfer capability used by a reliability coordinator or planning authority has not been submitted to the Commission, it is not possible to determine at this time whether FAC–012–1 satisfies the statutory requirement that a proposed Reliability Standard be just, reasonable, not unduly discriminatory or preferential, and in the public interest. Thus, the NOPR did not propose to approve or remand this Reliability Standard until the regional procedures are submitted.

778. The NOPR explained that FAC–012–1 only requires that the regional reliability organization provide documentation on transfer capability methodology and provide it to entities such as the relevant transmission planner, planning authority, reliability coordinator and transmission operator. The Reliability Standard does not contain clear requirements on how transfer capability should be calculated, which has resulted in diverse interpretations of transfer capability and the development of various calculation methodologies. The NOPR suggested that FAC–012–1 should, as a minimum, provide a framework for the transfer capability calculation methodology including data inputs and modeling assumptions. In addition, the NOPR asked for comments on the most efficient way to make the above information transparent for all participants.

i. Methodology

(a) Comments

779. APPA, International Transmission and MidAmerican agree that the proposed FAC–012–1 is not sufficient and should not be accepted for approval as a mandatory Reliability Standard. They suggest that, at a minimum, this Reliability Standard should provide a framework for the transfer capability calculation methodology, including data inputs and modeling assumptions. APPA notes that, in the Western Interconnection and ERCOT, the sets of rules for long-range and operational planning studies are transparent to all users, owners and operators and suggests that in the Eastern Interconnection, where multiple regions exist, the Regional Entities should consider developing an umbrella organization or process comprised of representatives from each of the Eastern Interconnection's Regional Entities to establish the planning and operational rules for the Interconnection. APPA suggests that this approach would work well to identify critical facilities, by using consistent and transparent study assumptions, and it would also minimize seams issues when establishing facility rating and transfer capabilities throughout the entire Interconnection. International Transmission states that this Reliability Standard should identify the performance that is required, that specifics of how transfer capability should be calculated do not belong in this Reliability Standard, and that a reference document could be developed for this purpose.

(b) Commission Determination

780. Although we are not proposing to approve or remand this Reliability Standard, because it is applicable to the regional reliability organization, the Commission agrees with APPA, International Transmission and MidAmerican that, at a minimum, this Reliability Standard should provide a framework for the transfer capability calculation methodology, including data inputs and modeling assumptions. The Commission agrees with APPA that there should be an umbrella organization to assure consistency within the Eastern Interconnection and the other interconnections. We believe that the best organization to do this would be the ERO, because it is the only organization with knowledge of all of the individual Regional Entities that can carry out this function. Therefore, we direct the ERO to modify this Reliability Standard to provide such a framework.

ii. Transparency and Confidentiality

(a) Comments

781. International Transmission cautions that, in making information regarding the framework for calculating transfer capability transparent to all participants, a balance must be maintained between the need for transparency and the need to maintain the confidentiality of sensitive critical energy infrastructure information (CEII). The results of certain critical contingency analyses would not be appropriate for public disclosure, but may be the basis for transfer capability limits imposed on some interfaces.

782. MidAmerican suggests that transparency could be provided in the Eastern Interconnection by each reliability coordinator and each planning authority posting the transfer capability calculations performed pursuant to FAC–012–1, along with a document outlining how they were determined and the purposes for which they are used on a protected Web site. The protected site should be accessible only to qualified entities. MidAmerican suggests that the Western Interconnection's approach, the WECC message system used for certain qualified paths, is an appropriately transparent system.

(b) Commission Determination

783. Although we are not proposing to approve or remand this proposed Reliability Standard, the Commission believes that it can be improved. The Commission believes that the process used to determine transfer capabilities should be transparent to the stakeholders, and agrees with International Transmission and MidAmerican that the results of those calculations should not be available for public disclosure but only for qualified entities on a confidential basis. In addition, the process and criteria used to determine transfer capabilities must be consistent with the process and

criteria used for other users of the Bulk-Power System. Simply stated, the criteria used to calculate transfer capabilities for use in determining ATC must be identical to those used in planning and operating the system. The Commission directs the ERO to take this into account in its Reliability Standards development process, and to modify the Reliability Standard consistent with Order No. 890 in Docket No. RM05–25–000.

784. Accordingly, the Commission affirms the NOPR proposal to not approve or remand this Reliability Standard. We understand that the ERO implemented its Reliability Standards development process to revise the Reliability Standard and will be submitting it in accordance with the schedule identified in Order No. 890.

g. Establish and Communicate Transfer Capability (FAC–013–1)

785. FAC–013–1 requires either the reliability coordinator or the planning authority, as determined by the regional reliability organization, to calculate transfer capabilities consistent with its transfer capability methodology and provide those capabilities to its transmission operators, transmission service providers and planning authorities.

786. In the NOPR, the Commission proposed to approve Reliability Standard FAC–013–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to develop a modification to FAC–013–1 that: (1) Makes it applicable to all reliability coordinators and (2) removes the regional reliability organization as the entity that determines whether a planning authority has a role in determining transfer capabilities.

i. Comments

787. APPA supports the Commission's proposal to approve FAC–013–1 as a mandatory and enforceable Reliability Standard, but disagrees with the Commission's proposed modification to remove the regional reliability organization as the entity that determines whether a planning authority has a role in determining transfer capabilities. APPA believes that regional committee processes are essential to determine, through their planning and operating committees, which planning authorities and reliability coordinators are responsible for determining and distributing each of the specific transfer capability values within each regional footprint. APPA proposes that in the Eastern Interconnection, where multiple regional reliability organizations and Regional Entities exist, the Regional Entities should consider developing an umbrella organization or process comprised of representatives from each of the Eastern Interconnection's Regional Entities, to establish the planning and operational planning rules for the Interconnection. APPA believes that such a program would minimize seams issues when establishing facility ratings and transfer capabilities throughout the entire Interconnection.

788. MidAmerican supports the Commission's proposal to make this Reliability Standard applicable to all reliability coordinators and planning authorities. MidAmerican believes in a clear separation of responsibilities between the reliability coordinators and planning authorities. MidAmerican believes that reliability coordinators should calculate transfer capabilities in the operating horizon, while planning authorities calculate transfer capabilities in the planning horizon, and would support additional clarification of the standard by explicitly stating the continued responsibility of planning authorities to calculate transfer capabilities for the planning horizon.

789. TANC is concerned that, if the transmission service provider and the transmission operators are specifically named in Requirement R2.1 of this Reliability Standard, but are not included in the Applicability section, this will cause ambiguity. TANC questions whether a transmission service provider or transmission operator that does not receive the transfer capabilities from the reliability coordinator will be held accountable and penalized for not producing the transfer capabilities when the reliability coordinator never provided them. If this is the case, TANC questions whether there will be different penalties for the transmission service provider and transmission operator, or whether they will be subject to the same penalties as the entities listed in the Applicability section.

790. EEI believes that the full range of issues discussed here are currently under review under Docket No. RM05–25 and proposes that these issues remain in a single forum to avoid confusion.

ii. Commission Determination

791. The Commission does not believe that the regional reliability organization should be able to decide the type of entity to which this Reliability Standard applies. The Commission disagrees with APPA that regional committee processes are essential to determine which planning authorities and reliability coordinators are responsible for determining and distributing each of the specific transfer capability values. Reliability coordinators have a wider-area view of the transmission system than planning authorities, which is important in calculating inter- and intra-regional transfer capabilities. Therefore, the Commission agrees with MidAmerican that reliability coordinators should calculate transfer capabilities in the operating horizon. The Commission will not address MidAmerican's proposal regarding calculating transfer capabilities in the planning horizon because those Reliability Standards are being considered in Docket No. RM07–3–000 and are therefore beyond the scope of this proceeding.

792. The Commission, as discussed elsewhere in this Final Rule, has considered APPA's proposal concerning creating an umbrella organization in regard to FAC–012–001.[276]

793. In regard to TANC's concern that transmission service providers and transmission operators may be liable because they are specifically named in Requirement R2.1, the Commission clarifies that, because the Reliability Standard only provides that the transmission service providers and transmission operators receive information regarding transfer capabilities, and does not require an affirmative action on the part of transmission service providers or transmission operators, a transmission service provider or transmission operator cannot be liable for violating the Reliability Standard.

794. The Commission disagrees with EEI that these matters should be evaluated only in the OATT Reform Proceeding. In Order No. 890, the Commission directed transmission owners to use the ERO's Reliability Standards development process to implement changes required in that Final Rule.[277]

795. Accordingly, the Commission approves Reliability Standard FAC–013–1 as mandatory and enforceable, and, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC–013–1 through the Reliability Standards development process that makes it applicable to reliability coordinators.

[276] *See supra* P 780.

[277] Order No. 890 at P 196.

6. INT: Interchange Scheduling and Coordination

796. The Interchange Scheduling and Coordination (INT) group of Reliability Standards addresses interchange transactions,[278] which occur when electricity is transmitted from a seller to a buyer across the power grid. Specific information regarding each transaction must be identified in an accompanying electronic label, known as a ''Tag'' or ''e-Tag'' which is used by affected reliability coordinators, transmission service providers and balancing authorities to assess the transaction for reliability impacts. Communication, submission, assessment and approval of a Tag must be completed for reliability consideration before implementation of the transaction.

a. Interchange Authority

797. The Version 1 INT Reliability Standards submitted with NERC's August 28, 2006 supplemental filing include a new entity, the interchange authority, which oversees interchange transactions and is included as an applicable entity or referenced in the Requirements sections of INT–005–1, INT–006–1, INT–007–1, INT–008–1, INT–009–1 and INT–010–1.[279] The Commission requested in the NOPR that NERC provide additional information regarding the role of the interchange authority so that the Commission could determine whether the interchange authority is a user, owner or operator of the Bulk-Power System required to comply with mandatory Reliability Standards.

i. Comments

798. ISO–NE states that it is unclear who the interchange authority should be, how its tasks could be performed operationally and how the interchange authority function relates to other reliability and market functions. ISO–NE states that NERC has not yet fully incorporated the concept of an interchange authority into its Functional Model and has not provided a means for an entity to register as an interchange authority under the Functional Model. Finally, ISO–NE states that NERC must still create a process to allow the appropriate entities to register as interchange authorities so that their status is clear to all applicable entities, and it urges that approval of the Reliability Standards that have the interchange authority as an applicable entity be withheld until these issues are resolved.

799. APPA agrees that applicability of the Reliability Standards to the interchange authority is confusing. However, APPA suggests the best approach to the problem is for NERC to identify the source and sink balancing authorities as the applicable entity in these Reliability Standards until the Functional Model is revised to better specify the status and responsibility of interchange authorities.

800. EEI observes that there is considerable confusion throughout the industry regarding the registration process and the relationship between registration and applicability of standards, with the interchange authority being an example of that confusion. However, EEI states it understands that the role of an interchange authority is currently being addressed and revisions to the Functional Model are currently moving through the approval process. If Version 3 of the Functional Model is approved by the NERC Board, EEI believes it will clarify that a sink balancing authority performing a Tag authority service could serve as an interchange authority and this modification would address the Commission's concern.

801. The CAISO suggests that it is premature to place any INT Reliability Standards involving an interchange authority into effect until more information is provided concerning the interchange authority's role.

ii. Commission Determination

802. The NERC glossary definition of interchange authority indicates that it is intended to provide essentially a quality control function in verifying and approving interchange schedules and communicating that information. Our understanding is that, in the interim, sink and source balancing authorities will serve as interchange authorities until the ERO has further clarified an interchange authority's role and responsibility in the modification of the Functional Model and in the registration process. The new interchange authority function allows an entity other than a balancing authority to perform this function in the future; the pre-existing INT–001–1 Reliability Standard identified the balancing authority as the responsible entity to perform this function. Any such entity should be registered by the ERO in the ERO compliance registry, so that the responsibility of an entity, other than a balancing authority, that takes on this role in the future would be clear.

803. In short, there is sufficient clarity concerning the nature and responsibilities of this function for it to be implemented at this time. Withholding approval of INT Reliability Standards pending further clarification on this matter would create an unnecessary gap in the coverage of the Reliability Standards that potentially could threaten the reliability of the Bulk-Power System.

b. Interchange Information (INT–001–2)

804. INT–001–1 seeks to ensure that interchange information is submitted to the reliability analysis service identified by NERC.[280] This Reliability Standard applies to purchasing-selling entities and balancing authorities. It specifies two Requirements that focus primarily on establishing who has responsibility in various situations for submitting the interchange information, previously known as transaction tag data, to the reliability analysis service identified by NERC. The Requirements apply to all dynamic schedules, delivery from a jointly owned generator and bilateral inadvertent interchange payback.

805. The Commission proposed in the NOPR to approve Reliability Standard INT–001–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of its regulations, the Commission proposed to direct NERC to submit a modification to INT–001–1 that: (1) Includes Measures and Levels of Non-Compliance and (2) includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and ''non-Order No. 888'' transfers.[281]

806. The Commission also noted in the NOPR that certain Requirements of INT–001–0 that relate to the timing and content of e-Tags had been deleted in the Version 1 Reliability Standard. NERC indicated that these Requirements are business practices that would be included in the next version of the NAESB Business Practices. The Commission stated in the NOPR that NERC's explanation of this change was acceptable and proposed to approve INT–001–1 with the deletion of Requirements R1.1, R3, R4 and R5. However, the Commission also noted that NAESB had not yet filed the e-Tagging requirements as part of its

[278] The NERC glossary defines ''interchange'' as ''Energy transfers that cross Balancing Authority boundaries.'' NERC Glossary at 9.

[279] The NERC Glossary defines an ''interchange authority'' as ''the responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.'' *Id.*

[280] Currently, the reliability analysis service used by NERC is the Interchange Distribution Calculator.

[281] This Requirement was included in INT–001–0 as Requirement R1.2.

business practices, and that if no such business practice has been submitted at the time of the Final Rule, the Commission may reinstate these Requirements in the Final Rule.

807. NERC submitted INT–001–2, which supersedes the Version 1 Reliability Standards, in its November 15, 2006 filing. INT–001–2 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, the Commission addresses INT–001–2, as filed with the Commission on November 15, 2006.

i. Comments

808. APPA states that NERC's submission of INT–001–2 on November 15, 2006 has fulfilled the Commission's proposed directive to include Measures and Levels of Non-Compliance in this Reliability Standard. APPA also states that, while it does not oppose NERC consideration of the Commission's proposed directive regarding the submission of interchange information for all point-to-point transfers entirely within a balancing authority area, it does not understand the Commission's reliability concerns in this connection.

809. MidAmerican states that it favors the Commission's proposed directive to NERC for a modification of the Reliability Standard as a substantial improvement for reliability. Constellation supports this proposal and states that the proposal, together with other initiatives, such as OATT reform, represent additional steps to achieving not only Bulk-Power System reliability, but also a reduction of undue discrimination in transmission services.

810. NERC disagrees with the Commission's proposal to direct the submission of interchange information on all point-to-point transfers within a balancing area. NERC contends that this issue was discussed at great length in the Reliability Standards development process and the vast majority of commenters and voters agreed that such a requirement would have no merit from a reliability perspective. It also states that such data is not used today by the NERC interchange distribution calculator for reliability.[282] Finally, NERC concludes that while it may be appropriate for this issue to be reconsidered in revisions to the Reliability Standards, a Commission directive to include a requirement that the collective expertise and the consensus of the industry have determined to be unnecessary for reliability constitutes ''setting the standard.''

811. LPPC agrees with the Commission that Requirements R1.1, R3, R4 and R5 are good business practices, and it states that for this reason they should not be included in the Reliability Standards. These business practices should more appropriately be contained in NAESB standards, or perhaps the *pro forma* OATT.

812. ERCOT maintains that INT–001–1 is not appropriate for the ERCOT region. ERCOT states that it is a single balancing authority. To the extent that INT–001–1 requires tagging transfers within a single balancing authority, it cannot be applied to ERCOT as written because all point-to-point transfers within ERCOT are financial transactions only. ERCOT notes that it tags transfers outside the ERCOT region.

813. Allegheny states that the requirement to tag point-to-point transactions cannot be met in the PJM market where Tags are not used when a transaction's source and sink are within the PJM footprint. Such transactions are reported through the PJM eSchedule system, which already provides adequate information for the PJM region to conduct reliability and curtailment analyses. Allegheny states that there is no reliability gap in the PJM market arising from this issue.

814. Santa Clara submits that LSEs should be applicable entities under proposed revised INT–001–2 to ensure that they have adequate notice of the requirements of this Reliability Standard. It states that the actions of LSEs are implicated in Requirement R1 of this proposed Reliability Standard.[283]

ii. Commission Determination

815. The Commission approves INT–001–2 as a mandatory and enforceable Reliability Standard. In addition, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process, as discussed below.

816. We agree with APPA that INT–001–2, submitted on November 15, 2006 includes Measures and Levels of Compliance, and we will not direct any further action regarding Measures and Levels of Compliance at this time.

817. MidAmerican and Constellation support the Commission's proposal that this Reliability Standard include a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and ''non-Order No. 888'' transfers. The Commission points out that unless these grandfathered and ''non-Order No. 888'' transfers are included in one of the INT Reliability Standards, they might not be subject to appropriate curtailment as necessary due to system conditions. Curtailments are determined using the interchange distribution calculator. Unless transactions internal to a balancing authority area are included in the calculator as we proposed, they are not recognized by the calculator and may never be curtailed. For instance, even if a transaction internal to a balancing authority area is non-firm and some inter-balancing authority trades are firm, the latter could be cut before the former, despite the curtailment priorities in the Order No. 888 tariff. While we recognize that most trades internal to a balancing authority area do not affect interchange, some do, since electricity flows do not necessarily follow the contract path.

818. In addition, e-Tagging of such transfers was previously included in INT–001–0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT–001–2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT–001–2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and ''non-Order No. 888'' transfers.

819. The Commission agrees with ERCOT's conclusion that the Reliability Standard does not apply to financial point-to-point transfers within the ERCOT region. This interpretation is consistent with the proposed INT Reliability Standards. Likewise, Allegheny's views on tagging point-to-point transactions within the PJM market are consistent with the proposed INT Reliability Standards.

820. With respect to Santa Clara's position that LSEs should be applicable entities under the Reliability Standard, the Commission notes that in situations where a LSE is securing energy from outside the balancing authority to supply its end-use customers, it would function as a purchasing-selling entity, as defined in the NERC glossary, and would be included in the NERC registry

[282] The NERC glossary defines the interchange distribution calculator as ''[t]he mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.'' NERC Glossary at 9.

[283] INT–001–2 Requirement R1 provides that the LSE and purchasing-selling entity shall ensure that arranged interchange is submitted to the interchange authority.

on that basis. This interpretation flows from the language of the Reliability Standards, and the Commission does not perceive any ambiguity in this connection. Nevertheless, the Commission directs the ERO to consider Santa Clara's comments, and whether some more explicit language would be useful, in the course of modifying INT–001–2 through the Reliability Standards development process.

821. The Commission accepts NERC's explanation that Requirements R1.1, R3, R4 and R5 of INT–001–0 that were deleted in INT–001–1 are business practices. NAESB voluntarily filed ''Standards for Business Practices and Communication Protocols for Public Utilities'' in Docket No. RM05–5–000 on November 16, 2006. This filing contains wholesales electric business practice standards that incorporate e-Tagging requirements and is the subject of a separate rulemaking process that is expected to result in rules that will become effective on or about the same time as the Reliability Standard becomes mandatory.

822. Accordingly, the Commission approves Reliability Standard INT–001–2 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT–001–2 through its Reliability Standards development process that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and ''non-Order No. 888'' transfers.[284]

c. Regional Difference to INT–001–2 and INT–004–1: WECC Tagging Dynamic Schedules and Inadvertent Payback

823. NERC proposed a regional difference that would exempt WECC from requirements related to tagging dynamic schedules and inadvertent payback. The Commission noted in the NOPR that WECC is developing a tagging requirement for dynamic schedules. The Commission requested information from NERC on the status of the proposed tagging requirement, the time frame for its development, its consistency with INT–001–1 and INT–004–1 and whether the need for an exemption would cease when the tagging requirements become effective. The Commission stated that it would not approve or remand an exemption until NERC submits this information.[285] Rather, we stated that we would consider any regional differences contained in a proposed WECC tagging requirement for dynamic schedules when submitted by NERC for Commission review.

i. Comments

824. APPA agrees with the Commission's proposed course of action addressing this regional difference.

825. Xcel requests that the Commission accept the proposed regional difference; tagging requirements for dynamic schedules do not apply now in WECC, and it would be burdensome and would provide little reliability benefit to apply those requirements to WECC by June 2007. The Commission therefore should approve the proposed variance for an interim period until WECC's tagging requirements for dynamic schedules are developed and approved.

ii. Commission Determination

826. The Commission stressed in Order No. 672 that uniformity of Reliability Standards should be the goal and practice, ''the rule rather than the exception.'' [286] The Commission therefore stated in the NOPR that the absence of a tagging requirement for dynamic schedules in WECC is a matter of concern, and that for this reason it could not approve or remand this regional difference without the additional information it requested. To date the Commission has not received this information. Of particular importance in this compliance filing will be the ERO's demonstration that this practice is due to a physical difference in the system or results in a more stringent Reliability Standard. Without this information, we are unable to address Xcel's comments further. The Commission therefore directs the ERO to submit a filing within 90 days of the date of this order either withdrawing this regional difference or providing additional information.

d. Regional Difference to INT–001–2 and INT–003–2: MISO Energy Flow Information

827. NERC proposed a regional difference that would allow MISO to provide market flow information in lieu of tagging intra-market flows among its member balancing authorities; the MISO energy flow information waiver is needed to realize the benefits of locational marginal pricing within MISO while increasing the level of granularity of information provided to the NERC TLR Process. The waiver request text states that it is understood that the level of granularity of information provided to reliability coordinators must not be reduced or reliability will be negatively affected. The waiver request text includes a condition specifying that the ''Midwest ISO must provide equivalent information to Reliability Authorities as would be extracted from a transaction tag.'' The Commission proposed in the NOPR to approve this regional difference. It explained there that, based on the information provided by NERC, the proposed regional difference is necessary to accommodate MISO's Commission-approved, multi-control area energy market. Thus, the Commission stated it believed that the regional difference is appropriate, because it is more stringent than the continent-wide Reliability Standard and otherwise satisfies the statutory standard for approval of a Reliability Standard.

i. Comments

828. APPA agrees with Commission's proposed course of action in approving this regional difference.

ii. Commission Determination

829. The information received by the Commission demonstrates that the proposed regional difference to INT–001–2 and INT–003–2, as filed on November 15, 2006, is necessary to accommodate MISO's Commission-approved, multi-control area energy market. The Commission concludes that the regional difference is appropriate, because it is more stringent than the continent-wide Reliability Standard and otherwise satisfies the statutory standard for approval of a Reliability Standard, and therefore approves it as mandatory and enforceable.

e. Interchange Transaction Implementation (INT–003–2)

830. The purpose of INT–003–1 is to ensure that balancing authorities confirm interchange schedules with adjacent balancing authorities before implementing the schedules in their area control error equations. INT–003–1 contains a Requirement that focuses on ensuring that a sending balancing authority confirms interchange schedules with its receiving balancing authority before implementing the schedules in its control area. The proposed Reliability Standard also requires that, for the instances where a high voltage direct current (HVDC) tie is on the scheduling path, both sending and receiving balancing authorities have to coordinate with the operator of the HVDC tie.

[284] The Requirement was included in INT–001–0 as Requirement R1.2.

[285] To date, the Commission has not received the requested information.

[286] Order No. 672 at P 290.

831. The Commission proposed in the NOPR to approve Reliability Standard INT–003–1 as mandatory and enforceable. In addition the Commission proposed to direct NERC to submit a modification to INT–003–1 that includes Measures and Levels of Non-Compliance.

832. NERC filed INT–003–2 with the Commission on November 15, 2006. This Reliability Standard supersedes the Version 1 Reliability Standard INT–003–1 and adds Measures and Levels of Non-Compliance.

i. Comments

833. APPA states that INT–003–2 fulfills the Commission's proposed directive to include Measures and Levels of Non-Compliance.

ii. Commission Determination

834. INT–003–1 serves an important purpose in requiring receiving and sending balancing authorities to confirm and agree on interchange schedules. With the addition of Measures and Levels of Non-Compliance, INT–003–2 addresses the Commission's only reservation regarding this Reliability Standard. Accordingly, the Commission approves Reliability Standard INT–003–2, as filed with the Commission on November 15, 2006, as mandatory and enforceable.

f. Regional Differences to INT–003–2: MISO/SPP Scheduling Agent and MISO Enhanced Scheduling Agent

835. NERC proposed a regional difference that would provide MISO and SPP with a variance from INT–003–1 to permit a market participant to use a scheduling agent to prepare a transaction Tag on its behalf.[287] In addition, NERC proposed the MISO Enhanced Scheduling Agent Waiver, which creates a variance from INT–003–1 for MISO that permits an enhanced single point of contact scheduling agent.

836. The Commission proposed in the NOPR to approve these two additional regional differences. The Commission explained that, based on the information provided by NERC, the proposed regional differences for this INT Reliability Standard would provide administrative efficiency, and provide equal or greater amounts of information to the appropriate entities as required in MISO's Commission-approved multi-control area energy market. The NOPR stated that the regional difference is appropriate because it is more stringent than the continent-wide Reliability Standard and otherwise satisfies the statutory standard for approval of a Reliability Standard.

i. Comments

837. APPA agrees with the Commission's proposed approval of these regional differences.

838. FirstEnergy states that it would be helpful if NERC clarified the function and effect of these waivers. FirstEnergy states that, where a specific task will be performed by another entity on behalf of the transferor, the transferor entity needs a delegation agreement, whereas in transferring a responsibility, the transferor entity needs a waiver. FirstEnergy states that currently balancing authorities are held accountable by regional reliability organizations for those functions the waivers transfer to the regional reliability organization. FirstEnergy suggests that NERC should clarify that, under these waivers, responsibility for complying with these Reliability Standards should be transferred to the RTOs that actually perform the tasks associated with these requirements.

ii. Commission Determination

839. These two variances from INT–003–2, as filed with the Commission on November 15, 2006, permit a market participant to use a scheduling agent to prepare a transaction tag on its behalf, providing administrative efficiency and providing equal or greater amounts of information to the appropriate entities as required in MISO's Commission-approved multi-control area energy market. This regional difference is appropriate because it is more stringent than the continent-wide Reliability Standard and otherwise satisfies the statutory standard for approval of a Reliability Standard. The Commission therefore approves the MISO/SPP Scheduling Agent Waiver and the MISO Enhanced Scheduling Agent Waiver as mandatory and enforceable regional differences to INT–003–2.

840. FirstEnergy may raise its suggestions in the Reliability Standards development process. However, we find that FirstEnergy's suggestion does not affect our decision to approve these two regional differences.

g. Dynamic Interchange Transaction Modifications (INT–004–1)

841. INT–004–1 seeks to ensure that dynamic transfers are adequately tagged to be able to determine their reliability impact. It requires the sink balancing authority, *i.e.,* the balancing authority responsible for the area where the load or end-user is located, to communicate any change in the transaction. It also requires the updating of Tags for dynamic schedules.

842. In the NOPR, the Commission proposed to approve Reliability Standard INT–004–1 as mandatory and enforceable. The Commission also proposed to direct NERC to submit a modification to INT–004–1 that includes Levels of Non-Compliance.

i. Comments

843. APPA agrees with the Commission that INT–004–1 can be approved as a mandatory and enforceable Reliability Standard. However, it suggests that the missing Levels of Non-Compliance should be developed and submitted for Commission approval before penalties are levied for violations.

ii. Commission Determination

844. As explained in the NOPR, while the Commission has identified concerns with regard to INT–004–1, this proposed Reliability Standard serves an important purpose by setting thresholds on changes in dynamic schedules for which modified interchange data must be submitted. Further, the Requirements set forth in INT–004–1 are sufficiently clear and objective to provide guidance for compliance. Accordingly, the Commission approves Reliability Standard INT–004–1 as mandatory and enforceable. In addition, the Commission directs the ERO to consider adding these Measures and Levels of Non-Compliance to the Reliability Standard.

h. Interchange Authority Distributes Arranged Interchange (INT–005–1)

845. INT–005–1 seeks to ensure the implementation of interchange between source and sink balancing authorities and that interchange information is distributed by an interchange authority to the relevant entities for reliability assessments.

846. The Commission proposed in the NOPR to approve Reliability Standard INT–005–1 as mandatory and enforceable. The Commission also proposed to direct NERC to submit a modification to INT–005–1 that includes Levels of Non-Compliance. Further, the Commission noted that INT–005–1 is applicable to the ''interchange authority'' and requested that NERC provide additional information regarding the role of the interchange authority so that the Commission can determine whether it is a user, owner or operator of the Bulk-Power System that is required to comply with mandatory Reliability Standards.

[287] NERC proposed three regional differences for INT–003–1 that would apply to MISO. One proposed regional difference was addressed in Reliability Standard INT–001–1. The remaining two are discussed here.

i. Comments

847. Comments on the interchange authority have been discussed above under the heading ''INT Reliability Standards General Issues.'' No other comments on INT–005–1 have been submitted.

ii. Commission Determination

848. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that, in the interim, source and sink balancing authorities will serve as interchange authorities until the ERO has clarified the role and responsibility of an interchange authority in the modification of the Functional Model and in the registration process.

849. The Commission is satisfied that the Requirements of INT–005–1 are appropriate to ensure that interchange information is distributed timely and available for reliability assessment. Accordingly, the Commission approves Reliability Standard INT–005–1 as mandatory and enforceable. In addition, the Commission directs the ERO to consider adding additional Measures and Levels of Non-Compliance to the Reliability Standard.

i. Response to Interchange Authority (INT–006–1)

850. INT–006–1 applies to balancing authorities and transmission service providers, and requires these entities to evaluate the energy profile and ramp rate of generation that supports interchange transactions in response to a request from an interchange authority to change the status of an interchange from an arranged interchange transaction to a confirmed interchange.

851. The Commission proposed in the NOPR to approve Reliability Standard INT–006–1 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to INT–006–1 that: (1) Makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review composite transactions from the wide-area reliability viewpoint and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation.

i. Comments

852. APPA agrees that INT–006–1 is sufficient for approval as a mandatory and enforceable reliability standard. However, APPA states that the Commission should merely instruct NERC to respond to the Commission's concerns and refrain from directing NERC to make specific changes to the Reliability Standard; APPA states that while the changes the Commission proposes may be appropriate, it should be left to NERC's expertise and the Reliability Standards development process to address the Commission's concerns.

853. FirstEnergy agrees that it is appropriate for the reliability coordinator to be included in the applicability section. However, it argues that it is impracticable in large organized markets, such as those of MISO and PJM, for a local entity, such as a transmission operator, to review wide-area transactions, and it does not improve reliability to do so. Transactions occurring totally within the market operation are provided as part of network service net scheduled interchange.

854. EEI states that the ''wide-area reliability impact'' review envisioned by the Commission, which involves review of the composite energy interchange transactions, probably already takes place under Reliability Standards INT–005 through INT–009 in a cost-effective manner. EEI explains that since most transactions submitted by wholesale markets to the transactions tagging process span multiple hours with varying sizes (in MW), and are often submitted days before transaction start times, the wide-area review consists of ensuring that sufficient generator ramping capability exists, as well as examining for limits on transfer capabilities. This review is generally considered sufficient to the extent that analyses are taking place on the basis of projected system conditions. EEI suggests that the Commission-proposed review and validation of composite energy interchange transactions by reliability coordinators might be more effectively addressed through ''near real-time'' system review. It explains that, at this time, the broad range of system condition parameters is better known, and the reliability coordinators can make use of the TLR process to maintain system reliability.

855. Entergy disagrees with the Commission's proposed modifications. It contends that they will require substantial changes to the tagging specifications. Entergy believes that the Commission's concerns may already be addressed by Reliability Standards INT–005 through INT–009.

856. MISO believes the Reliability Standards and e-Tag specifications already require reliability entities to evaluate and approve e-Tags. It questions the value of specifying reliability coordinators and transmission operators as applicable entities because their responsibilities are already laid out in the Reliability Standards.

857. Northern Indiana contends that the NOPR's discussion of INT–006–1 is unclear and confusing. It states that it does not understand what the Commission means by ''validate'' when the Commission proposes that reliability coordinators and transmission operators review and validate composite arranged interchanges. Northern Indiana also questions whether both reliability coordinators and transmission operators would be required to validate and approve the Tags and what the basis for approval would be. It questions what falls within the term ''potential detrimental reliability impact,'' what happens if a Tag is not validated within 20 minutes to the hour, and whether all schedules are canceled outright or passively approved.

858. TVA suggests that the term ''composite Tag'' should be defined as part of the proposed modifications. CAISO also questions the meaning of ''composite Tag'' and seeks clarification on that issue. TVA notes that depending on the type of reliability analysis required to validate a ''composite Tag,'' it may prove impractical to conduct this evaluation for hourly transactions.

859. CAISO states that neither NERC nor the Commission has identified a deficiency in the current interchange reliability assessment process or a pressing reliability need for this Reliability Standard. CAISO also has concerns about meeting the Commission-proposed directives regarding INT–006–1 since reliability coordinators and transmission operators within the Western Interconnection currently do not have a common database from which to draw the information needed to review composite transactions from a wide-area reliability viewpoint. CAISO requests the Commission to consider whether the Western Interconnection should comply with these proposed Requirements at all or whether a transition period is appropriate.

ii. Commission Determination

860. The Commission approves INT–006–1 as mandatory and enforceable. In addition, we direct that NERC develop modifications to the Reliability Standard, as discussed below.

861. The Commission remains convinced that a proactive approach is superior to a reactive approach in maintaining system reliability. While EEI and Entergy claim that reliability

coordinators and transmission operators' involvement in reliability reviews of interchange transactions are covered in INT–005 through INT–010, and MISO claims that such review is covered in other Reliability Standards, we note the following: References to reliability coordinator and transmission operator involvement are virtually absent from the INT Reliability Standards. One finds such references only in Requirement R2 of INT–010, which deals with interchange coordination exemptions, and there the involvement of reliability coordinators is restricted to situations that involve current or imminent reliability-related reasons for action. We cannot find any Requirements in the remaining INT Reliability Standards that require a wide-area reliability assessment, regardless of the time periods, by a reliability coordinator; wide-area reliability assessment, moreover, can only be carried out by reliability coordinators.

862. With respect to MISO's comment on the value of applying the Reliability Standard to reliability coordinators and transmission operators given that the Reliability Standards and the e-Tag specification already require evaluation and active approval of reliability entities on e-Tags, we note that none of the INT Reliability Standards have those requirements and that the e-Tag specification is not part of the mandatory Reliability Standards. Like reliability coordinators who are responsible for reliable operation of entire reliability coordinator areas, a transmission operator is the reliability entity responsible for its local area operations. Interchange transactions would be likely to reduce system reliability if those transactions are not reviewed and approved by the appropriate reliability entities before implementation.

863. With respect to the question raised by TVA and CAISO on the definition of ''composite Tags,'' we expressed our reliability concerns in the NOPR and explained that reliability coordinators and transmission operators should review composite energy interchange transaction information (composite Tags) for wide-area reliability impact. In addition, we stated that when the review indicated a potential detrimental reliability impact, the reliability coordinator or transmission operator should communicate to the sink balancing authority the necessary transaction modifications before implementation.[288] While we did not require a specific notification time prior to actual transactions, this proactive approach should promote system reliability.

864. We agree with FirstEnergy that it is appropriate to include reliability coordinators as applicable entities for purposes of conducting wide-area reliability assessments; in large organized markets transmission operators may not be appropriate for this purpose because they do not have a wide-area view.

865. While we did not address review time frames in the NOPR, we are in general agreement with EEI's suggestion that ''near-real time'' system review by reliability coordinators may be more practical, while still being efficient and effective in achieving reliability goals. A proactive approach, *i.e.* one that involves reliability coordinators in a way that permits them to make wide-area assessments of composite interchange transactions for purposes of evaluating reliability impact, including identifying potential IROL violations and mitigating them using TLR procedures before they become actual IROL violations, is far superior to a reactive approach, *i.e.*, one that brings reliability coordinators in after the fact to invoke TLR procedures to avoid an IROL violation or other operating actions to extricate the system from reliability problems such as an actual IROL violation.

866. The Commission stated in Order No. 672 that it expected entities to use the Reliability Standards development process to address their concerns about a Reliability Standard. With respect to CAISO's request that the Commission consider whether the Western Interconnection needs to comply with these Requirements at all or whether a transition period is appropriate, since CAISO did not raise either concern in the Reliability Standards development process, and others in the Western Interconnection have not raised a similar concern, CAISO should raise this issue in the Reliability Standards development process in the first instance. Reliability Standard INT–006–1 will apply to CAISO.

867. Accordingly, the Commission approves Reliability Standard INT–006–1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT–006–1 through the Reliability Standards development process that: (1) Makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation. We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.

j. Interchange Confirmation (INT–007–1)

868. Reliability Standard INT–007–1 requires that before changing the status of submitted arranged interchanges to confirmed interchanges, the interchange authority must verify that the submitted arranged interchanges are valid and complete with relevant information and approvals from the balancing authorities and transmission service providers. The Commission proposed in the NOPR to approve INT–007–1 as mandatory and enforceable.

i. Comments

869. APPA agrees with the Commission that INT–007–1 is sufficient for approval as a mandatory and enforceable Reliability Standard, subject to NERC's plans for the registration of entities as interchange authorities.

ii. Commission Determination

870. The Commission approves Reliability Standard INT–007–1 as mandatory and enforceable. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that in the interim source and sink balancing authorities will serve as interchange authorities until the ERO has clarified the role and responsibility of an interchange authority in the modification of Functional Model and in the registration process.

k. Interchange Authority Distribution of Information (INT–008–1)

871. INT–008–1 requires the interchange authority to distribute information to all balancing authorities, transmission service providers and purchasing-selling entities involved in the arranged interchange when the status of the transaction has changed from arranged interchange to confirmed interchange. The Commission proposed in the NOPR to approve INT–008–1 as mandatory and enforceable.

i. Comments

872. APPA agrees with the Commission that INT–008–1 is sufficient for approval as a mandatory and enforceable Reliability Standard,

[288] NOPR at P 219.

subject to NERC's plans for the registration of entities as interchange authorities. It suggests that NERC should clarify which reliability entities have the responsibility for ensuring that interchange information is coordinated between the source and sink balancing authorities before implementing the Reliability Standard. APPA also states that NERC should modify this Reliability Standard to make clear what entities it in fact would apply to.

ii. Commission Determination

873. The Commission approves Reliability Standard INT–008–1 as mandatory and enforceable. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that a source and sink balancing authority will serve as the interchange authority until the ERO has clarified the role and responsibility of an interchange authority in the modification of the Functional Model and in the registration process. Finally, we direct the ERO to consider APPA's suggestions in the Reliability Standards development process.

l. Implementation of Interchange (INT–009–1)

874. Reliability Standard INT–009–1 seeks to ensure that the implementation of an interchange between source and sink balancing authorities is coordinated by an interchange authority. The Commission proposed in the NOPR to approve INT–009–1 as mandatory and enforceable.

i. Comments

875. APPA agrees with the Commission that INT–009–1 is sufficient for approval as a mandatory and enforceable Reliability Standard, subject to NERC's plans for the registration of entities as interchange authorities. It suggests that NERC modify its Functional Model to clarify which reliability entities have the responsibility for ensuring proper implementation of interchange transactions that have received reliability assessments. APPA also suggests that NERC modify this Reliability Standard to make clear what entities it in fact would apply to.

ii. Commission Determination

876. The Commission approves Reliability Standard INT–009–1 as mandatory and enforceable. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that a source and sink balancing authority will serve as the interchange authority until the ERO has clarified the role and responsibility of an interchange authority in the modification of the Functional Model and in the registration process. Finally, we direct the ERO to consider APPA's suggestions concerning this Reliability Standard in the Reliability Standards development process.

m. Interchange Exemptions (INT–010–1)

877. INT–010–1 allows reliability entities to initiate or modify certain types of interchange schedules under abnormal operating conditions and to be exempt from compliance with other INT Reliability Standards.

878. The Commission explained in the NOPR that Reliability Standard INT–010–1 includes provisions that allow modification to an existing interchange schedule or submission of a new interchange schedule that is directed by a reliability coordinator to address current or imminent reliability-related reasons. The Commission interpreted these current or imminent reliability-related reasons as not including actual IROL violations, since they require immediate action so that the system can be returned to a secure operating state as soon as possible and no longer than 30 minutes after a reliability-related system interruption—a period that is much shorter than the time that is expected to be required for new or modified transactions to be implemented.

879. The Commission proposed to approve INT–010–1, interpreted as set forth above, as mandatory and enforceable.

i. Comments

880. Northern Indiana supports the Commission's interpretation of INT–010–1, but it requests that the Reliability Standard be modified to explicitly state that it does not include actual IROL violations.

881. ISO–NE supports Commission approval of INT–010–1, but does not share the Commission's concerns regarding the initiation or modification of interchange schedules to address SOL or IROL violations. It states that interchange schedules can in certain circumstances provide an additional effective tool to help prevent an SOL and IROL violation. While ISO–NE recognizes that other tools may in certain circumstances be more effective, it states that this neither diminishes the value nor precludes the use of the tools contained in INT–010–1. ISO–NE also notes that section 2.4 of INT–010–1, which describes Level 4 Non-Compliance, should be edited to state that ''[t]here shall be a level four non-compliance * * *.'' instead of ''[t]here shall be a level three non-compliance * * *.''

882. APPA agrees with the Commission that INT–010–1 is sufficient for approval as a mandatory and enforceable Reliability Standard, but APPA does not agree with the Commission's interpretation of the Reliability Standard. APPA explains that the stated purpose of INT–010–1 is to allow certain types of interchange schedules to be initiated or modified by reliability entities and to be exempt from compliance with other interchange standards under abnormal operating conditions. This Reliability Standard in effect authorizes reliability coordinators to direct, and balancing authorities to take, remedial actions to adjust interchange schedules immediately and then document these actions after the fact. INT–010–1 thus provides the emergency waiver from other INT Reliability Standards that makes adjusting interchange schedules the appropriate response to a SOL or IROL. APPA states that the Commission's proposed interpretation therefore should not be adopted.

883. EEI cautions against adopting the Commission's interpretation of INT–010–1. EEI believes that the existing standard meets the Commission's expectation, *i.e.*, permitting and encouraging immediate action to alleviate an SOL or IROL. EEI explains that without INT–010–1, all interchange scheduling and schedule modifications would go through the normal process contained in INT–005 through INT–009. Only INT–010 would allow a balancing authority to make an immediate interchange action without obtaining a Tag. Within 60 minutes of the action, the balancing authority would follow up with the necessary documentation and carry forward the action, if necessary. In the absence of INT–010–1, a balancing authority taking such action would be in violation of INT–009 for failing to comply with the normal process requirements.

884. EEI notes by way of example that, to relieve an SOL or IROL, a reliability coordinator requires immediate offsetting changes in the net scheduled interchange of ACE equations of source and sink balancing authorities. Within 60 minutes following the action, the reliability authority directs the balancing authority to reflect the schedule change event using an arranged interchange. The tagging activity ensures coordination going forward and provides a written record. All of this takes place after the operational tasks pertaining to the action to alleviate the SOL or IROL,

consistent with Commission expectations.

ii. Commission Determination

885. For the reasons and interpretation noted in the NOPR, the Commission approves INT–010–1 as mandatory and enforceable.

886. The Commission believes that our interpretation of INT–010–1 is consistent with the way APPA and EEI understand the Reliability Standards. The Commission believes that making a modification to an existing interchange schedule on paper for current or imminent reliability-related situations involving actual IROL violations is ineffective because its implementation usually takes much longer than the 30-minute period that is allowed in the relevant IRO or TOP Reliability Standards. However, the Commission interprets INT–010–1 as allowing the actual physical transaction to be modified to alleviate an IROL event without first documenting the modification. The interchange schedule would then be modified after the fact to document the physical actions taken.

887. With regard to ISO–NE's statement that interchange schedules can, in certain circumstances, provide an additional effective tool to help prevent SOL and IROL violations while other tools may, in certain circumstances, be more effective, the Commission clarifies that our concern is related to using interchange schedules to address actual IROL violations. We have no concern in using this as a tool help prevent potential SOL and IROL violations as asserted by ISO–NE. We further note that the phrase in Requirements R2 and R3 ''current or imminent reliability-related reasons'' can be interpreted as potential or actual IROL violations set forth in the comments from Northern Indiana, ISO–NE, APPA and EEI, and therefore modifications to INT–010–1 are needed.

888. Accordingly, the Commission approves Reliability Standard INT–010–1 as mandatory and enforceable. In addition, we adopt the interpretation set forth in the NOPR that these current or imminent reliability-related reasons do not include actual IROL violations, since they require immediate control actions so that the system can be returned to a secure operating state as soon as possible and no longer than 30 minutes after a reliability-related system interruption—a period that is much shorter than the time that is expected to be required for new or modified transactions to be implemented. Finally, we direct the ERO to consider Northern Indiana and ISO–NE's suggestions in the Reliability Standards development process.

7. IRO: Interconnection Reliability Operations and Coordination

889. The Interconnection Reliability Operations and Coordination (IRO) group of Reliability Standards detail the responsibilities and authorities of a reliability coordinator.[289] The IRO Reliability Standards establish requirements for data, tools and wide-area view, all of which are intended to facilitate a reliability coordinator's ability to perform its responsibilities and ensure the reliable operation of the interconnected grid.

a. Reliability Coordination—Responsibilities and Authorities (IRO–001–1)

890. IRO–001–1 requires that a reliability coordinator have reliability plans, coordination agreements and the authority to act and direct reliability entities to maintain reliable system operations under normal, contingency and emergency conditions.

891. In November 2006, NERC submitted IRO–001–1, which includes Measures and Levels of Non-Compliance.[290] In addition, while the Version 0 Reliability Standard applied to reliability coordinators and regional reliability organizations, IRO–001–1 would in addition apply to transmission operators, balancing authorities, generator operators, transmission service providers, LSEs and purchasing-selling entities. The Version 1 Reliability Standard does not modify or add any Requirements, and it appears that the change in applicability corresponds to existing Requirement R8, which provides that transmission operators, balancing authorities, generator operators, transmission service providers, LSEs and purchasing-selling entities ''shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements.''

892. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to Requirement R1 of IRO–001–0 that: (1) Reflects the process set forth in the NERC Rules of Procedures and (2) eliminates the regional reliability organization as an applicable entity.

i. Comments

893. APPA supports the approval of the Reliability Standard but expresses concern that the Version 1 standard does not include Measures that correspond to Requirements R2 and R9. APPA emphasizes the need for Measures corresponding to Requirement R9, which requires the reliability coordinator to act in the interests of reliability for the overall reliability coordinator area and the Interconnection before the interests of any other entity. APPA supports Requirement R8 with the extended applicability, provided that applicability is determined by reference to the NERC compliance registry. APPA agrees that the regional reliability organization should be eliminated as an applicable entity and suggests it be replaced with Regional Entities.

894. FirstEnergy suggests that NERC clarify whether Requirement R8, which requires entities to comply with a reliability coordinator directive ''unless such actions would violate safety, equipment or regulatory or statutory requirements,'' refers to personnel safety, equipment safety or both. In addition, it suggests the establishment of a chain of command so that, for example, if a generator receives conflicting instructions from a balancing authority and a transmission operator, it can determine which instruction governs.

895. Requirement R3 provides that a reliability coordinator ''shall have clear decision-making authority to act and direct actions to be taken'' by applicable entities to ''preserve the integrity and reliability of the Bulk Electric System and these actions shall be taken without delay but no longer than 30 minutes.'' Santa Clara contends that some actions would require driving to a remote site and therefore, mandating completion of the required action within 30 minutes would be unreasonable. Thus, it recommends that NERC modify Requirement R3 to provide that ''actions shall commence without delay, but in any event shall commence within 30 minutes.''

896. California Cogeneration comments that the Reliability Standard fails to address the operational limitations of QFs because they have contractual obligations to provide thermal energy to their industrial hosts.

[289] According to the NERC glossary, at 15, a reliability coordinator is ''the entity with the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations * * *.''

[290] IRO–001–1 supercedes the Version 0 Reliability Standard. In this Final Rule, we review the November version, IRO–001–1.

It contends that a QF can be directed to change operations only in the case of a system emergency, pursuant to 18 CFR 292.307.

ii. Commission Determination

897. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, as a separate action under section 215(d)(5), the NOPR proposed to direct the ERO to develop modifications to Requirement R1 [291] to substitute ''Regional Entity'' for ''regional reliability organization'' and reflect NERC's Rules of Procedure for registering, certifying and verifying entities, including reliability coordinators. Commenters do not raise any concerns regarding the proposed action. Accordingly, for the reasons stated in the NOPR, the Commission approves IRO–001–1 as mandatory and enforceable. In addition, for the reasons discussed in the NOPR, the Commission directs the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process that reflect the process set forth in the NERC Rules of Procedures and eliminate the regional reliability organization as an applicable entity.[292]

898. While APPA, FirstEnergy and California Cogeneration suggest possible changes to IRO–001–1, they do not suggest that the proposed Reliability Standard should not be approved. The ERO should consider the commenters' suggestions when modifying the Reliability Standard pursuant to its Reliability Standards development process. Further, the Commission directs the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard as requested by APPA.

899. However, we disagree with Santa Clara's suggested change regarding the 30-minute limit to implement a corrective control action in Requirement R3. When system integrity or reliability is jeopardized, *e.g.*, exceeding IROLs or SOLs, the relevant reliability entities must take corrective control actions to return the system to a secure and reliable state as soon as possible and in no longer than 30 minutes. This is important to satisfy the relevant Reliability Standards such as IRO–005–0 and TOP–004–0 to minimize the amount of time the system operates in an insecure mode and is vulnerable to cascading outages.

b. Reliability Coordination—Facilities (IRO–002–1)

900. IRO–002–1 establishes the requirements for data, information, monitoring and analytical tools and communication facilities to enable a reliability coordinator to meet the reliability needs of the Interconnection, to act in addressing real-time emergency conditions and to control analysis tools.[293]

901. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification that: (1) Includes Measures and Levels of Non-Compliance and (2) modifies Requirement R7 to explicitly require a minimum set of tools for the reliability coordinator.

i. Comments

902. Dominion agrees with the proposal to require a minimum set of tools for reliability coordinators, explaining that such specificity is needed to ensure that proactive efforts to maintain reliability are being continuously pursued. According to Dominion, a general requirement for ''adequate'' tools is insufficient and the proposal to modify IRO–002–1 is appropriate since it will ensure that operators have a minimum set of tools with which to perform their duties.

903. In contrast, both APPA and LPPC ask the Commission to reject the proposal to require a minimum set of tools because flexibility is needed to allow change as technology improves over time. LPPC states that the Commission should, instead, require a listing of capabilities that is not tied to a particular product or tool. APPA contends that, because the Measures now require the reliability coordinator to provide specifications to the Regional Entity to be in compliance, the Regional Entity will set the minimum standards for reliability tools. Further, according to APPA, setting a minimum requirement would establish a ''lowest common denominator'' that might prove counterproductive.

904. MRO states that IRO–002–0 is another Reliability Standard for which it will be difficult to identify Measures and Levels of Non-Compliance because the Requirements include terms like ''adequate,'' ''potential,'' ''could result'' and ''as required.''

ii. Commission Determination

905. NERC's November 2006 revision to the Reliability Standard satisfies the proposal to include Measures and Levels of Non-Compliance. While MRO comments that it will be difficult to identify Measures and Levels of Non-Compliance, it does not provide any specific suggestions for changes to NERC's proposal.

906. Further, consistent with the NOPR, the Commission directs the ERO to modify IRO–002–1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe that this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions. Further, as noted by Dominion, such a requirement promotes a more proactive approach to maintaining reliability.

907. With respect to the concerns of APPA and LPPC, the Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time. We disagree with APPA that our concern is addressed by the new Measures as they neither specify a minimum set of capabilities nor require any uniformity among reliability coordinators or Regional Entities. We do not believe that the identification of minimum capabilities translates to ''lowest common denominator'' as suggested by APPA. If the Reliability Standards development process results in developing a ''lowest common denominator'' Reliability Standard that is geared toward guaranteeing compliance and avoiding penalties as opposed to ensuring reliability, the Commission could remand such a Reliability Standard.[294]

908. We disagree with MRO that it will be difficult to identify Measures and Levels of Non-Compliance since the Requirements include terms like ''adequate,'' ''potential,'' ''could result'' and ''as required.'' Many tariffs on file with the Commission do not specify every compliance detail, but rather provide some level of discretion as necessary to carry out a particular act. This does not mean the tariffs are unenforceable; rather, it means that, if a

[291] Requirement R1 of IRO–001–1 provides that each regional reliability organization, ''subregion'' or ''Interregional Coordinating group'' shall establish one or more reliability coordinators to continuously assess transmission reliability and coordinate emergency operations. *See* NOPR at P 506.

[292] *See* NOPR at P 505–06.

[293] In its November 15, 2006, filing, NERC submitted IRO–002–1, which supercedes the Version 0 Reliability Standard. IRO–002–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, IRO–002–1.

[294] *See* Order No. 672 at P 329.

dispute arises over compliance and there is a legitimate ambiguity regarding a particular fact or circumstance, that ambiguity can be taken into account in the exercise of the Commission's enforcement discretion.

909. As we stated in the NOPR,[295] Reliability Standard IRO–002–1 serves an important purpose in ensuring that reliability coordinators have the information, tools and capabilities to perform their functions. The Measures and Levels of Non-Compliance submitted by NERC further enhance the Reliability Standard. Accordingly, the Commission approves Reliability Standard IRO–002–1 as mandatory and enforceable. In addition we direct the ERO to develop a modification to IRO–002–1 through the Reliability Standards development process that requires a minimum set of tools that should be made available to reliability coordinators.

c. Reliability Coordination—Wide Area View (IRO–003–2)

910. The purpose of IRO–003–2 is for a reliability coordinator to have a wide-area view of its own and adjacent areas to maintain situational awareness. Wide-area view also facilitates a reliability coordinator's ability to calculate SOL and IROL as well as determine potential violations in its own area.[296]

911. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification that includes: (1) Measures and Levels of Non-Compliance and (2) criteria to define the term ''critical facilities'' in a reliability coordinator's area and its adjacent systems.

i. Comments

912. APPA agrees that IRO–003–2 is sufficient for approval as a mandatory and enforceable Reliability Standard. However, APPA suggests that, instead of merely including criteria to define critical facilities as proposed, NERC and each Regional Entity should establish, document, use and make transparent the methodology, data and procedures they use to determine ''critical facilities.''

913. Entergy agrees with the need for the criteria, but cautions that it must be flexible enough to allow for changing conditions experienced in real-time operations. Xcel notes that the term ''critical facilities'' is not defined and suggests that the Reliability Standard not be approved until the term is defined.

ii. Commission Determination

914. For the reasons stated in the NOPR,[297] the Commission approves proposed Reliability Standard IRO–003–2 as mandatory and enforceable. NERC's November 2006 revision to the Reliability Standard satisfies the proposal to include Measures and Levels of Non-Compliance.

915. Further, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we adopt in the Final Rule the proposal to direct that the ERO develop a modification to the Reliability Standard through the Reliability Standards development process to create criteria to define the term ''critical facilities'' in a reliability coordinator's area and its adjacent systems. In developing the required modification, the ERO should consider the suggestions of APPA, Entergy and Xcel.

d. Reliability Coordination—Operations Planning (IRO–004–1)

916. The purpose of IRO–004–1 is to require each reliability coordinator to conduct next-day operations reliability analyses to ensure that the system can be operated reliably in anticipated normal and contingency system conditions. Operations plans must be developed to return the system to a secure operating state after contingencies and shared with other operating entities.

917. In the NOPR, the Commission proposed to approve Reliability Standard IRO–004–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to IRO–004–1 that requires the next-day analysis to identify effective control actions that can be implemented within 30 minutes during contingency conditions.

i. Comments

918. APPA agrees that IRO–004–1 is sufficient for approval as a mandatory Reliability Standard and that the Requirements are sufficiently clear and objective to provide a basis for issuing a remedial action directive. However, it contends that many Requirements lack Measures and Levels of Non-Compliance, and the ERO and Regional Entities should not assess penalties until additional Measures and Levels of Non-Compliance are developed.

919. Entergy agrees that a mitigation plan for potential operating problems identified in the next-day analysis may be an appropriate requirement, but cautions that it would be inappropriate to penalize an entity that chooses an alternate mitigation strategy when the issues arise in real time based on system conditions prevalent at that time.

920. APPA, in contrast, disagrees with the proposed directive to identify effective control actions in the next-day analysis. It contends that real-time conditions are seldom the same as predicted in the day-ahead schedule, and state estimators using real-time operating conditions are much more accurate than analyses based on day-ahead schedules.

921. FirstEnergy contends that IRO–004–1 should require a day-ahead planning process and reflect activities inherent within a market operation.

922. Northern Indiana contends that the Commission's proposed directive is unclear. It asks whether the Commission is requiring the reliability coordinator to secure the system to an N–2 state, rather than an N–1 state within the next-day planning analysis. It contends that currently the Reliability Standard is N–1, and requests clarification that the Commission did not intend to mandate an increase in security from N–1 to N–2 in the NOPR.

923. California PUC agrees that there is merit in requiring system operators to assess the outlook for the following day, but nevertheless is concerned with the Commission's proposed directive. Its main concern is that the list of identified control actions can be too long or too generic to be effective to address the myriad potential system contingencies that could arise on the next day.

924. California Cogeneration states that the proposed Reliability Standard allows reliability coordinators to require data on gross load and generation behind the site boundary meter, which is contrary to a prior Commission order.[298]

ii. Commission Determination

925. For the reasons stated in the NOPR,[299] the Commission approves proposed Reliability Standard IRO–004–1 as mandatory and enforceable. In

[295] NOPR at P 511.

[296] In its November 15, 2006, filing, NERC submitted IRO–003–2, which supersedes the Version 0 Reliability Standard. IRO–003–2 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, IRO–003–2.

[297] *See* NOPR at P 519.

[298] *California Independent System Operator Corp.*, 96 FERC ¶ 63,015 at 7 (2001). It states in part ''The intent of the Commission's directive was to remove the requirement to provide any behind-the-meter information, whether on generation or load.''

[299] *See* NOPR at P 529.

addition, the Commission directs the ERO to develop modifications to the Reliability Standard, as discussed below.

926. We agree with Entergy that system operators must make their decision to use the most effective control action based on the prevailing system conditions, to return the system to a secure state following a contingency. Therefore, the chosen control action may be different than those identified in next-day operations planning. We reiterate that our intent is to require a comprehensive next-day operations planning study that includes identification of effective solutions to aid system operators in real-time operations.

927. We disagree with APPA's comment that day-ahead planning to identify effective control actions would not enhance system reliability because we believe this is also the intent of the ERO for including such a Requirement in this Reliability Standard.[300] Our proposed directive is to augment the Requirement that the plans to alleviate SOL and IROL violations are assessed to ensure that the control actions can be implemented and effective within 30 minutes after a contingency.

928. We agree with APPA that state estimators and real-time contingency analyses using real-time operating conditions produce more accurate study results compared to those from next-day operations planning analyses that are based on day-ahead schedules and forecast conditions. However, we remain convinced that a proactive approach that includes identification of effective operating solutions to deal with contingencies is far superior to a reactive approach that identifies solutions when the system conditions prevail in real-time operations. The former can identify solutions that may not be otherwise available to the system operators—*e.g.* certain planned generation or transmission outages are approved conditional upon re-affirmation prior to their removal from service or a short recall time subject to certain system conditions developing in real-time operations.

929. We disagree with FirstEnergy that IRO–004–1 should include the day-ahead planning process and reflect activities inherent in a market operation because day-ahead planning includes financial activities that may not occur in real-time. The Commission believes that, for reliability purposes, the simulation should include only what will actually occur.

930. The proposed Reliability Standards IRO–005–1 and TOP–004–0 require that in the event of an IROL violation, *i.e.* power flow on an interface exceeding its IROL, the system must be returned to a secure state within 30 minutes regardless of the cause of the violation, so that the system is once again capable of withstanding the next contingency without resulting in cascading failures.

931. In response to Northern Indiana, our intent is not to mandate an increase in security from N–1 to N–2, but rather is to ensure there is no reliability gap in the IROL-related Reliability Standards. To do this, the Commission believes it is necessary to provide operators with control actions needed to mitigate an IROL violation while within the 30-minute period after a first contingency. We are not requiring an increase to N–2, which would require planning the system for any two contingencies at all times.

932. With respect to California PUC's comment, we note that it is just as important for day-ahead operation planners to review and derive system operating limits to deal with a myriad of contingencies for different system configurations and generation dispatches, as it is for them to assess the feasibility of returning the system to a secure operating state after these contingencies have occurred. Similar to reviewing and deriving SOLs and IROLs to ascertain that system reliability will be maintained based on the most onerous forecast conditions and critical contingencies, identifying corrective control actions would not encompass each and every contingency and system condition. This is because previous operating experiences and established operating practices would have covered a significant portion of the contingencies and the corresponding control actions already.

933. We further note that for those few IROL contingencies under the forecast and most onerous system conditions, if operation planners equipped with a suite of off-line analytical tools, but without any burden, distraction or interference from real-time operations, cannot identify the effective control actions, it can be argued that it would be unrealistic to expect system operators to do so with an additional requirement—*i.e.* identification and implementation of an effective control action all within 30 minutes. In addition, the control actions identified in the next-day analysis may quite often provide relevant information to the system operators of the control options they have available.

934. We believe that our use of NERC's definition of bulk electric system in combination with its registration process should assuage California Cogeneration's concerns.

935. In response to APPA's concern that NERC did not provide a Measure for each Requirement, we reiterate that it is in the ERO's discretion whether each Requirement requires a corresponding Measure. The ERO should consider this issue through the Reliability Standards development process.

936. Accordingly, we approve Reliability Standard IRO–004–1 as mandatory and enforceable. Further, we direct the ERO to modify IRO–004–1 through the Reliability Standards development process to require the next-day analysis to identify control actions that can be implemented and effective within 30 minutes after a contingency. The Commission also directs the ERO to consider adding Measures and Levels of Non-Compliance to the Reliability Standard as requested by APPA.

e. Reliability Coordination—Current Day Operations (IRO–005–1)

937. IRO–005–1 ensures energy balance and transmission reliability for the current day by identifying tasks that reliability coordinators must perform throughout the day.

938. In the NOPR, the Commission proposed to approve Reliability Standard IRO–005–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to IRO–005–1 that includes Measures and Levels of Non-Compliance. The Commission proposed that the Measures and Levels of Non-Compliance specific to IROL violations should be commensurate with the magnitude, duration, frequency and causes of the violation. Further, the Commission proposed to direct the ERO to conduct a survey on IROL practices and actual operating experiences, and indicated that it may propose further modifications to IRO–005–1 based on the survey results.[301]

[300] IRO–004–1 Purpose Statement states in part ''Plans must be developed to alleviate SOL and IROL violations.''

[301] NOPR at P 545 (''We propose to direct NERC to perform a survey of present operating practices and actual operating experience concerning drifting in and out of IROL violations. As part of the survey, we will require reliability coordinators to report any violations of IROLs, their causes, the date and time of the violations, and the duration in which actual operations exceeded IROL to the ERO on a monthly basis for one year beginning two months after the effective date of the Final Rule.'')

i. Comments

939. FirstEnergy supports the approval of the proposed Reliability Standard as mandatory and enforceable as interpreted by NERC (*i.e.*, that exceeding IROL for less than 30 minutes is not a violation), pending further action through the NERC Reliability Standards development process.

940. MidAmerican supports the Commission's proposed survey and notes that based on its experience, IROL violations have been faithfully reported across NERC.

941. The CAISO urges the Commission to proceed with caution if headed in the direction of absolute compliance with IROL. However, it supports the survey to determine the extent to which systems are actually ''drifting'' in and out of IROL limits.

942. APPA indicates its support of the Commission's directive to undertake a survey regarding IROL practices and experiences. However it feels that it should be NERC's role to decide on the survey. It contends that, based on the survey results and using the Reliability Standard development process, NERC would decide what modifications to IRO–005–2 are appropriate.

943. Entergy agrees that it is appropriate to use a mitigation plan to resolve an SOL or IROL violation when the actual contingency that causes an SOL or IROL violation is experienced. However, with an acceptable mitigation plan, it is not necessary to require transmission operators to keep facility loading below a level where a potential SOL or IROL violation would occur assuming a low probability of the contingency. Entergy requests clarification that the Commission's guidance is not intended to preclude the use of such alternative procedures. The Commission should be cautious not to restrictively define SOL or IROL in a manner that causes the system operator to take preemptive action through this Reliability Standard to address events that may technically be SOL or IROL violations, but which have a low probability of occurrence and can be mitigated through other proven procedures.

944. ISO–NE agrees that NERC should promptly address the ambiguities in the current definition of an IROL. It has a concern that the phrase ''The Transmission Service Provider shall respect these SOLs and IROLs'' in Requirement R14 may cause confusion that this entity is expected to respect SOLs and IROLs in the operating time frame.[302]

945. TAPS raises an issue with Requirement R13 that states in part ''[i]n instances where there is a difference in derived limits,* * * Load-Serving Entities * * * shall always operate the Bulk Electric System to the most limiting parameter.'' TAPS further states that, since LSEs do not operate the system within SOLs or IROLs, the only thing such entities, particularly small ones, can do is shed load. It contends that if the Reliability Standard is mandatory, it should apply only within the parameters proposed by NERC—subject to its Bulk Electric System definition and its June registry criteria. Further, given the apparent error in the Reliability Standard, the Commission should ask NERC to re-examine it.

ii. Commission Determination

946. The Commission approves proposed Reliability Standard IRO–005–1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process, as discussed below.

947. The Commission clarifies the intent of and need for the proposed survey. We reiterate that the intent is to learn about the operating experiences and practices of operating entities; specifically, how they operate their systems to respect IROLs in the normal system conditions, *i.e.* prior to a contingency. The survey results will facilitate future development and modifications of IROL-related Reliability Standards to better clarify and eliminate potential multiple interpretations of respecting IROLs that may exist in the proposed Reliability Standards.[303] In addition, the survey will identify the reliability risks and the frequency and number of operating practices involving drifting in and out of IROL.[304] The survey results will also provide guidance on the frequency, duration and magnitude of IROL violations, their causes and whether these IROL violations occur during normal or contingency conditions.

948. We note the support from FirstEnergy, MidAmerican, CAISO and APPA for our proposed survey. Regarding MidAmerican's comment that reporting on IROL violations is a routine practice, we note that the proposed Reliability Standards only require reporting on those violations that have exceeded IROLs for longer than 30 minutes. The current reporting requirements and results will not provide an adequate assessment of the existing operating practices regarding IROLs and the reliability risks and the extent of drifting in and out of IROLs.

949. In response to Entergy, the Commission believes that operating the system within IROL under normal system condition and exceeding IROL only after a contingency and subsequently returning the system to a secure condition as soon as possible, but no longer than 30 minutes, may be appropriate. This mode of operation will minimize the system risk of being one contingency away from potential cascading failures.

950. ISO–NE asks that the ERO should promptly clarify the current definition for IROL violations. However, we do not share ISO–NE's concern that transmission service providers may be responsible for respecting SOLs and IROLs in real-time operation. Requirement R14 only requires a transmission service provider to use the SOLs and IROLs provided by the reliability coordinator in its tariff, it does not require any action in the operating time frame.

951. We do not share TAPS' concern regarding LSEs initiating load shedding as their own control action to respect IROLs or SOLs. The appropriate control actions to respect IROLs and SOLs are the responsibilities of a reliability coordinator and transmission operator. If load shedding is required, it is the responsibility of a reliability coordinator or a transmission operator to direct the appropriate entities including LSEs to carry it out. However, we urge the ERO to provide further clarification in this regard and include TAPS' concern in developing the modification of this Reliability Standard.

952. Accordingly, the Commission approves Reliability Standard IRO–005–1 as mandatory and enforceable.

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[302] IRO–005–1 Requirement R14 states ''Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Provider shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.''

[303] NOPR at P 540: IRO–005–1 could be interpreted as allowing a system operator to respect IROLs in two possible ways: (1) Allowing IROL to be exceeded during normal operations, *i.e.*, prior to a contingency, provided that corrective actions are taken within 30 minutes or (2) exceeding IROL only after a contingency and subsequently returning the system to a secure condition as soon as possible, but no longer than 30 minutes. Thus, the system can be one contingency away from potential cascading failure if operated under the first interpretation and two contingencies away from cascading failure under the second interpretation.

[304] The term ''drifting in and out of IROLs'' refers to operating the normal system (*i.e.* prior to a contingency) with frequent occurrences in which IROLs are exceeded, but each occurrence lasting less than 30 minutes. Currently, this mode of operation is not considered as a violation of NERC Reliability Standards.

Further, because IRO–005–1 has no Measures or Levels of Non-Compliance, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to IRO–005–1 through the Reliability Standards development process that includes Measures and Levels of Non-Compliance. The Commission further directs that the Measures and Levels of Non-Compliance specific to IROL violations must be commensurate with the magnitude, duration, frequency and causes of the violations and whether these occur during normal or contingency conditions. Finally, the Commission directs the ERO to conduct a survey on IROL practices and actual operating experiences by requiring reliability coordinators to report any violations of IROL, their causes, the date and time, the durations and magnitudes in which actual operations exceeds IROLs to the ERO on a monthly basis for one year beginning two months after the effective date of the Final Rule. We may propose further modifications to IRO–005–1 based on the survey results.

f. Reliability Coordination—Transmission Loading Relief (IRO–006–3)

953. IRO–006–3 ensures that a reliability coordinator has a coordinated method to alleviate loadings on the transmission system if it becomes congested to avoid limit violations. IRO–006–3 establishes a detailed Transmission Loading Relief (TLR) process for use in the Eastern Interconnection to alleviate loadings on the system by curtailing or changing transactions based on their priorities and according to different levels of TLR procedures.[305] The proposed Reliability Standard includes a regional difference for reporting market flow information to the Interchange Distribution Calculator rather than tagged transaction information for the MISO and PJM areas. It also includes by reference the equivalent Interconnection-wide congestion management methods used in the WECC and ERCOT regions.

954. In the NOPR, the Commission proposed to approve Reliability Standard IRO–006–3 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to IRO–006–3 that: (1) Includes a clear warning that a TLR procedure is an inappropriate and ineffective tool to mitigate IROL violations; (2) identifies in a Requirement the available alternatives to use of the TLR procedure to mitigate an IROL violation and (3) includes Measures and Levels of Non-Compliance that address each Requirement. In addition, the Commission proposed to approve the WECC and ERCOT load relief procedures as superior to the national standard.

i. Comments

955. APPA agrees that IRO–006–3 is sufficient for approval as a mandatory Reliability Standard. It suggests that the ERO should consider development of detailed Measures and Levels of Non-Compliance that address each Requirement in IRO–006–3. Until then, penalties should not be imposed except for egregious violations and the associated penalties should be imposed by the Commission.

956. APPA, Entergy and MidAmerican agree that the TLR procedure is an inappropriate and ineffective tool to mitigate actual IROL violations and that a clear warning to that effect should be included. MidAmerican specifically suggests that the warning must also apply to actual emergency situations in addition to actual IROL violations.

957. Similarly, ISO–NE supports the Commission's conclusions with regard to reliance on TLRs to address actual IROL violations. Further, it supports the Commission's proposal that the ERO should modify the Reliability Standard to provide flexibility for ISOs and RTOs to rely on redispatch as a means to mitigate an IROL violation.

958. Xcel suggests that instead of the proposed modification of a clear warning, it should include a requirement that TLR procedures should not be used for alleviating actual IROL violations. It asserts that the latter approach would be more measurable than the Commission's proposed modification.

959. Entergy and MidAmerican believe that TLR procedures can be an effective mechanism to avoid potential SOL and IROL violations or potential emergency situations.

960. In contrast, Progress Energy disagrees with the Commission's reasoning on the ineffectiveness of using TLR procedures to alleviate actual IROL violations.

ii. Commission Determination

961. The Commission approves IRO–006–3 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to the Reliability Standard as discussed below.

962. The Commission remains convinced, based on Blackout Recommendation No. 31,[306] the submissions from APPA, Entergy, MidAmerican, ISO–NE and Xcel, and NERC's comments on the Staff Preliminary Assessment,[307] that proposed directives to include a clear warning that a TLR procedure is an inappropriate and ineffective tool to mitigate IROL violations and to identify the available alternatives to use of the TLR procedure to mitigate an IROL violation are the appropriate improvements to address the deficiencies in using TLR procedures to mitigate actual IROL violations or actual emergency situations. The Commission endorses Blackout Recommendation No. 31.

963. The Commission agrees with Entergy and MidAmerican that TLR procedures can be an effective mechanism to avoid potential IROL violations and potential emergencies. Regarding this, we reiterate that our concerns have always been on the use of TLR to mitigate actual IROLs or actual emergencies, and not on potential IROLs or emergencies, as indicated in the Blackout Report, Staff Assessment and the NOPR.

964. We do not understand Progress Energy's disagreement because no reason is provided.

965. Accordingly, in addition to approving the Reliability Standard, the Commission directs the ERO to develop a modification to IRO–006–3 through the Reliability Standards development process that (1) includes a clear warning that the TLR procedure is an inappropriate and ineffective tool to mitigate actual IROL violations and (2) identifies in a Requirement the available alternatives to mitigate an IROL violation other than use of the TLR procedure. In developing the required modification, the ERO should consider the suggestions of MidAmerican and Xcel. In addition, the Commission approves the WECC and ERCOT load relief procedures as superior to the national Reliability Standard. As identified in the NOPR, the Commission directs the ERO to modify the WECC and ERCOT procedures to ensure

[305] The equivalent Interconnection-wide transmission loading relief procedures for use in WECC and ERCOT are known as ''WSCC Unscheduled Flow Mitigation Plan'' and Section 7 of the ''ERCOT Protocols,'' respectively.

[306] Blackout Recommendation No. 31, at 163 is to ''Clarify that the transmission loading relief (TLR) process should not be used in situations involving an actual violation of an Operating Security Limit.''

[307] The NERC comments to Staff Assessment at 49 state that ''NERC agrees that the TLR procedure alone is usually not effective as a control measure to mitigate an IROL violation and explains that the TLR procedure was not intended to be effective in this manner.''

consistency with the standard form of the Reliability Standards including Requirements, Measures and Levels of Non-Compliance.[308]

g. Regional Difference to IRO–006–3: PJM/MISO/SPP Enhanced Congestion Management (Curtailment/Reload/Reallocation)

i. Background

966. As explained in the NOPR, IRO–006–003 provides for a regional difference for MISO, PJM and SPP.[309] According to NERC, the regional difference is needed to allow RTO market practices, simplify transaction information requirements for market participants, and provide reliability coordinators with appropriate information for security analysis and curtailments, reloads, reallocations and redispatch requirements.

967. The regional difference to IRO–006–3 applies the congestion management process included in Joint Operating Agreements filed by MISO, PJM and SPP and specified in seams agreements reached among MISO, PJM, and their neighboring non-market areas during the RTOs' market formation and expansions. Under the congestion management process in the waiver, each RTO calculates an amount of energy (market flow) flowing across coordinated flowgates. These market flows are separated into their appropriate priorities based on the RTO's schedules and reservations and are available for curtailment under the appropriate TLR Levels in the NERC interchange distribution calculator. Under the TLR method for curtailing interchange transactions and in the per generator method for generation-to-load impacts, NERC uses a five percent curtailment threshold, but in the waiver, the RTO's market flows with an impact of greater than zero percent on a coordinated flowgate are represented and made available for curtailment under the appropriate TLR priorities.

968. In their comments on the Staff Preliminary Assessment, MISO–PJM contended that there is unduly discriminatory treatment of the market flows of MISO and PJM versus the generation-to-load impacts of non-market entities because the waiver subjects the RTOs to curtailment (and the corresponding redispatch costs) in circumstances where the non-market entities would not be subject to curtailment.

969. In the NOPR, the Commission did not propose to approve or remand this regional difference.

ii. Comments

(a) Application of the Regional Difference

970. MISO–PJM contends that there is unduly discriminatory treatment against market flows of MISO and PJM during the application of the TLR Standard. The RTOs argue that NERC should modify IRO–006–3 and the MISO and PJM regional difference to require modifying the market flow threshold used by the interchange distribution calculator to assign relief obligations to MISO, PJM, and SPP from zero to a standard percentage that is technically feasible to implement on a non-discriminatory basis, netting of market flow impacts, tag impacts, and generation-to-load impacts, and reporting to the interchange distribution calculator all net generation-to-load impacts for both market and non-market transmission providers. Constellation supports MISO–PJM's argument that there is unduly discriminatory treatment of the MISO and PJM market flows compared to the generation-to-load impacts of non-market entities in the application of the TLR standard.

971. MISO–PJM indicates that they have raised the equity issue with the NERC Operating Reliability Subcommittee (Operating Subcommittee), that their markets currently are being asked to curtail market flow impacts down to zero percent while tagged transactions and generation-to-load impacts during TLR 5 are being asked to curtail impacts that are five percent or greater. MISO–PJM states that the NERC Operating Subcommittee has indicated that they will address reliability issues only and that they are not the appropriate group to address equity issues.

(b) Seams Agreements

972. Several entities argue that the Commission should not overturn the existing IRO–006–3 regional difference. MidAmerican states that MISO and PJM should continue to pursue a negotiated solution to the issues outlined in MISO–PJM's filings. Mid-Continent states that the Commission should reject the MISO–PJM proposal to require NERC to allow them to report only the transactions with five percent or greater impacts on flowgates rather than report all transactions for curtailments, since MISO and PJM offered to report all transactions to avoid negative impacts on the reliability of the transmission system. Mid-Continent argues that not doing so would impact the reliability of the transmission system.

973. Mid-Continent asks the Commission to not implement MISO and PJM's proposal to modify NERC's procedures and to not override seams agreements. MidAmerican claims that MISO–PJM comments amount to an abrogation of existing seams agreements. MidAmerican states that the seams agreements were negotiated in a give-and-take process between the parties resulting in the existing waiver which was proposed by PJM and MISO in response to Commission orders. MidAmerican states that if any changes are sought to these waivers, they should be addressed in negotiation with the appropriate parties. MidAmerican suggests that any changes should be requested by way of the NERC process for developing Reliability Standards and that any negotiated agreements should be presented to the Commission for approval. Mid-Continent claims that MISO–PJM have not provided valid reasons to replace the current Reliability Standards or to take actions that would modify existing seams agreements signed by MISO and PJM. Mid-Continent asks the Commission not to short-circuit the NERC Reliability Standards process which will give full consideration to the reliability implications of MISO's and PJM's proposal.

974. APPA agrees with the Commission's proposed approach in allowing MISO, PJM, NERC and other ''relevant entities'' to continue their negotiations regarding this regional difference. APPA cautions that any agreement reached by NERC and approved by the Commission regarding a regional difference for this Reliability Standard should be governed by reliability considerations and should not permit market design considerations to override NERC's Reliability Standards. MidAmerican suggests a process where the RTOs invite parties to reconsider the seams agreements, the parties negotiate changes, the Commission approves new agreements and waivers are then sought from NERC to the extent necessary. MidAmerican argues that since the RTOs do not allege any reliability problem there is no need to reject or upend the existing NERC waiver.

(c) Modifying the Congestion Management Process and Alternatives for Temporary Application of the Waiver

975. Mid-Continent states that it agrees with the Commission's proposal to not adopt MISO and PJM's request to instruct NERC to modify the current waiver to the TLR in the RTOs and believes that instead the Commission should direct NERC to address these issues through the Reliability Standards

[308] *See* NOPR at P 564–65.

[309] NOPR at P 568.

development process with input from neighboring systems. Mid-Continent states that changes to the waiver must not discriminate against non-market regions; must not negatively impact the reliability of neighboring systems and must be consistent with seams agreements signed by the RTOs.

976. NRECA claims that issues associated with market flows and generation-to-load impacts have not been resolved and is concerned that MISO–PJM's suggestion that ''consensus'' has been reached on the issues is premature. NRECA is also concerned that implementation of the MISO and PJM proposal could increase reliance on TLRs. NRECA urges the Commission to not short circuit or circumvent the Reliability Standards development process or the RTO stakeholders process and states that the Commission should permit the stakeholders to reach full consensus.

977. MISO–PJM indicates that they have been working with both the NERC Operating Subcommittee and the Congestion Management Process Working Group (Congestion Working Group) to achieve a consensus on these changes, and that based on this, the Commission stated in the NOPR that it prefers that MISO, PJM and others continue negotiations to resolve these issues rather than imposing a solution on market participants. MISO–PJM state that they have held extensive discussions with a group composed of NERC Operating Subcommittee and Congestion Working Group participants. MISO–PJM indicates that detailed analyses has been performed to evaluate the effect of changing the market flow threshold from zero percent to five percent in one percent increments and that the NERC Operating Subcommittee has recommended that the market flow threshold used by the interchange distribution calculator to assign relief obligations to the MISO, PJM, and SPP be changed from zero percent to three percent for a 12 month interim period. MISO–PJM assert that at the end of the 12 months, a decision will be made whether to recommend a permanent change to the market flow threshold from zero percent to three percent or a change to some other value. MISO–PJM state that according to the NERC Operating Subcommittee, this recommendation is to only address the reliability issue raised by MISO, PJM and SPP so that they are able to meet their relief assignment during TLR.

978. MISO–PJM also states that to receive congestion management process Council endorsement and support for the change being developed by the NERC Operating Subcommittee group, it requires unanimous approval by the congestion management process Council and that, though the 12 month field test to change the market flow threshold from zero percent to three percent has the support of MISO, PJM, SPP and TVA, it does not have the unanimous approval of all signatories to the seams agreements. MISO–PJM states that MAPPCOR (MAPP) has not agreed to the field test recommended by the NERC Operating Subcommittee and that MAPP has asserted that MISO should continue to honor their contractual obligation and report market flow impacts down to zero percent for relief assignments as specified in the MISO–MAPP Seams Operating Agreement. MISO is concerned that once the field test is complete and the NERC Operating Subcommittee recommends the use of a three percent threshold or some other threshold to address the reliability issue, the MISO may still have a contractual obligation with MAPP to use market flows down to zero percent for relief assignments. MISO–PJM states that this contractual obligation can only be altered if MISO and MAPP can agree on a change to the Seams Operating Agreement but expects resistance to change the Seams Operating Agreement. MISO and PJM do not believe they can address the equity issue by continuing discussions with the NERC Operating Subcommittee.

979. MISO–PJM also state that by continuing to use market flows down to zero percent for relief assignments on reciprocally coordinated flowgates between MISO and MAPP, there will be situations where MISO is unable to meet its relief obligation. MISO–PJM states that they have sought unsuccessfully to execute redispatch agreements with those parties who have direct counter-flow on the identified flowgates where the MISO is unable to meet its relief obligation. MISO–PJM believe that the Commission should address this continuing discriminatory treatment of the market impacts on flowgates. MISO–PJM state that of the three areas where MISO–PJM raised comments on discriminatory treatment of the markets, only one area (changing the market flow threshold for a 12 month field test) has resulted in steps being taken to address the discriminatory treatment and that even this one area can only be considered a partial success because there is only a solution to address the reliability issue, but not the equity issue.

980. MISO–PJM explain in their supplemental comments that NERC has demonstrated a willingness to consider the reliability issue by authorizing a 12 month field test allowing PJM, MISO and SPP market flows to use a three percent threshold, to observe the impact on reliability, but will not address what it refers to as ''equity issues.'' MISO–PJM explains the field test has been approved by all the reciprocal entities that have signed seams agreements except MAPP. MISO–PJM state that, at the end of the 12 months, a decision will be made whether to use a three percent threshold or some other threshold to address the reliability concerns. MISO–PJM explain that the same entities that make up the Mid-Continent objected to the field test because they asserted MISO has a contractual obligation under the MAPP Seams Operating Agreement to continue reporting its market flows down to zero percent. MISO–PJM contend that because the MISO has agreed to honor its contractual obligation during the field test and will continue to use a zero percent threshold for all flowgates that are reciprocal between MISO and MAPP, this means that the flowgates under the control of the Mid-Continent parties will not participate in the field test and NERC will have no data to show the impact of changing the market flow threshold to three percent on these flowgates.

981. MISO–PJM state that as long as the regional difference does not become a mandatory standard during the field test, they are satisfied that appropriate steps are being taken to address reliability.

(d) Reporting of Generator to Load Impacts by Non Market Areas

982. MISO–PJM supports modifications to the TLR process that would require all participants (both market and non-market) to report their market flow impacts and generator-to-load impacts to the interchange distribution calculator and honor their allocations when they report their firm versus their non-firm usage. MISO–PJM believes that taking this step would also address the threshold equity issue and the netting issue because all entities would be subject to the same treatment. MISO–PJM requests that the Commission to either direct NERC to initiate a process to modify the interchange distribution calculator such that market flows and generator-to-load impacts from non-market areas are both reported to the interchange distribution calculator and are subject to curtailment based on their priorities from the allocations or that the Commission take action to do so.

983. MISO–PJM states that the reporting of generator-to-load impacts by the non-market entities is the one area that is not currently under

discussion with a stakeholder group. MISO–PJM explains that both the market and non-market entities receive an allocation on flowgates and that both the market entities and the non-market entities use the allocations when selling firm transmission service. MISO–PJM states that only the market entities report their market flows to the interchange distribution calculator and use their allocations to determine what portion of market flows will be considered firm and believe that the non-market entities could also report their firm and non-firm generator-to-load usage to the interchange distribution calculator and receive relief assignments based on this usage. MISO–PJM indicates that this would remove the assumption that all generator-to-load impacts from the non-market entities represent firm usage. MISO–PJM states that reporting relief obligations by one group of participants and not reporting by the other results in conflicting actions during the TLR process because market entities suffer the financial consequences of redispatch at the same time reliability is not being accomplished due to off-setting actions by non-market entities.

984. MISO–PJM states that, to address the discriminatory treatment of the markets, the Commission could order the TLR Reliability Standard to be modified to have the market entities discontinue reporting their market flows to the interchange distribution calculator. MISO–PJM believes that instead of this order, the preference is to have the market entities continue reporting their market flow impacts and the non-market entities report their generator-to-load impacts to the interchange distribution calculator. The allocations would be used to set the priority of these impacts.

985. Mid-Continent states that the regional difference requiring PJM and MISO to report all flows instead of net flows was part of the commitments MISO and PJM made to meet NERC's tagging requirements. Mid-Continent contends that it is appropriate to treat MISO–PJM market flows differently because they are greater than the system flows that resulted from control area-based system operation. Mid-Continent further claims that MISO cannot achieve the redispatch the interchange distribution calculator requires because of MISO's own actions since MISO does not report actual flows to the interchange distribution calculator and MISO and PJM's congestion management tools do not utilize all redispatch options.

(e) Accounting for Counter Flows During TLR

986. MISO–PJM state that there have been discussions at the NERC Operating Subcommittee about taking into account counter-flows during TLR when assigning relief. MISO–PJM contends that by considering counter-flows, those entities that are responsible for the loading problem on a net basis will be responsible for fixing the loading problem during TLR. MISO–PJM states that the MISO, PJM and SPP markets operate on a net flow basis and, therefore, have additional reasons for wanting to consider counter-flows. MISO–PJM expects that by summer 2007, the Task Force will have a recommendation on netting in the interchange distribution calculator for the NERC Operating Subcommittee to consider. MISO–PJM state that it is premature to speculate on the outcome of the discussions with the NERC Operating Subcommittee at this time. MISO–PJM clarifies that they are not asking the Commission to take any action on this issue but to let the NERC Operating Subcommittee address the technical merits of netting impacts in the interchange distribution calculator.

987. Mid-Continent states that eliminating the requirements to report flows in both directions may adversely impact reliability because the interchange distribution calculator will not have enough information to assign responsibilities to the contributors of a constraint.

iii. Commission Determination

988. The Commission will not approve or remand this regional difference. The treatment of the market flows of MISO–PJM versus the generation-to-load impacts of non-market entities in the application of the TLR standard has been addressed by the Commission in a number of cases.[310] In approving the plans of various transmission owning utilities to join PJM, the Commission attached several conditions including a requirement that certain non-market utilities be held harmless from effects of loop flow and congestion resulting from the utilities' RTO choices.[311] Further, during MISO's market start up,[312] the Commission determined that the markets could not start without the MISO having at least a specific, transparent plan for how it will handle the interface of multiple transmission tariffs and market-to-non-market seams [313] and required the MISO to file any resolution of seams, or a status report of progress on seams resolution including detailed plans as to how MISO will address seams absent agreements, within 60 days of the date of the order. The regional difference to IRO–006–3 applies the congestion management process that was included in the Joint Operating Agreement filed by MISO, PJM and SPP and that was specified in the seams agreements reached between MISO, PJM, and their neighboring non-market areas in order to meet the Commission's requirements described above.[314]

989. The Commission recognizes MISO–PJM's concerns that: (1) The congestion management process could be placing an undue burden on the RTO regions to provide redispatch especially on remote flowgates where an RTO's dispatch has a small impact and (2) under the congestion management process, the calculation of market flows for relief assignments on Reciprocal Coordinated Flowgates between the MISO and MAPP could create situations where MISO is unable to meet its relief obligation without curtailing load. We also understand that these concerns are exacerbated by the possibility of civil penalties for non-compliance with the requirement to use market flows down to zero percent for relief assignments on reciprocal coordinated flowgates between MISO and MAPPCOR. Especially during transitions when markets with multiple control areas are started up, markets are expanded to include other control areas, or non-market control areas are consolidated, this can have an effect on the loop flows experienced by neighboring regions and the redispatch required by the neighboring regions due to fewer tagged transactions reported to the interchange distribution calculator. The Commission recognizes that there are concerns by neighboring entities to be held harmless from increased redispatch responsibility caused by these transitions.

[310] *See Alliance Companies,* 100 FERC ¶ 61,137 (2001) and *Midwest Independent Transmission System Operator, Inc. and PJM Interconnection,* L.L.C., 106 FERC ¶ 61,251 (2004).

[311] *Commonwealth Edison Company and American Electric Power Service Corporation,* 106 FERC ¶ 61,250 (2004). This order required ComEd to demonstrate that its proposal held utilities in Wisconsin and Michigan harmless from all adverse impacts associated with loop flow or congestion that would result from its choice to join PJM.

[312] *See Midwest Independent Transmission System Operator, Inc.,* 108 FERC ¶ 61,163 (2004).

[313] To resolve this issue, the Commission encouraged market participants to use the PJM-Midwest ISO joint operating agreement as a model or starting point for seams agreements, particularly with respect to the seams with the various utilities in the MAPP region.

[314] *See Midwest Independent Transmission System Operator, Inc.,* 110 FERC ¶ 61,290 (2005).

990. The Commission concludes that the issues described by MISO–PJM (*i.e.*, defining the obligation of a certain region to provide redispatch when a flowgate becomes congested) are best handled through seams agreements rather than being subject to the NERC processes. We recognize that the two areas of seams agreements and Reliability Standards could overlap if the agreements reached do not allow for reliable outcomes where parties can achieve the relief assigned. As such, the Commission will neither approve nor remand the waiver of the regional difference to IRO–006–3 while the 12-month field test allowing PJM, MISO and SPP market flows to use a three percent threshold is being conducted. After the 12-month field test is complete, the Commission will reexamine approving the waiver as a mandatory and enforceable Reliability Standard.

991. The Commission instructs the RTOs to continue working with the non-market regions to develop revised seams agreements that allow for equitable and feasible treatment of market flows in the NERC TLR/redispatch process. The solution should not harm system reliability and should not subject either non-RTO transmission owners or the RTO markets to unreasonable redispatch responsibilities. We note that if consensus cannot be reached, the RTOs may file a section 205 or section 206 proposal to revise the terms and conditions of the congestion management process if the terms agreed on in the seams agreements and Joint Operating Agreement have become unjust or unreasonable or may file to terminate the agreements as allowed in the seams agreements.

992. The Commission will not adopt MISO–PJM's proposal to require non-market entities to report their generator-to-load impacts to the interchange distribution calculator with the allocations used to set the priority of these impacts in this Reliability Standards process. If NERC determines that this information and corresponding curtailment options are needed for reliability, NERC should file to modify IRO–006–3 to include these additions. However, the economic implications of the reporting of generator-to-load impacts by non-market entities are not in the scope of the reliability process and are better addressed on a case-by-case basis or, as appropriate, in the proceeding on RTO Border Utility Issues.[315]

993. In addressing MISO–PJM's claim that the ERO should modify IRO–006–3 and the MISO–PJM regional difference to require netting generation-to-load impacts to recognize counterflow, we will let the ERO Operating Subcommittee address the technical merits of netting flow impacts in the interchange distribution calculator.

h. Procedures, Processes, or Plans To Support Coordination Between Reliability Coordinators (IRO–014–1)

994. The stated purpose of IRO–014–1 is to ensure that each reliability coordinator's operations are coordinated so that they will not have an adverse reliability impact on other reliability coordinator areas and to preserve the reliability benefits of interconnected operation. Specifically, IRO–014–1 ensures energy balance and transmission by requiring a reliability coordinator to have operating procedures, processes or plans for the exchange of operating information and coordination of operating plans.

995. In the NOPR, the Commission proposed to approve IRO–014–1 as mandatory and enforceable.

i. Comments

996. APPA agrees with the Commission's proposed approval of IRO–014–1 as mandatory and enforceable.

ii. Commission Determination

997. For the reasons stated in the NOPR, the Commission approves IRO–014–1 as mandatory and enforceable.

i. Notifications and Information Exchange Between Reliability Coordinators (IRO–015–1)

998. IRO–015–1 establishes Requirements for a reliability coordinator to share and exchange reliability-related information among its neighbors and participate in agreed-upon conference calls and other communication forums with adjacent reliability coordinators.

999. In the NOPR, the Commission proposed to approve IRO–015–1 as mandatory and enforceable.

i. Comments

1000. APPA agrees with the Commission's proposed approval of IRO–015–1 as mandatory and enforceable.

ii. Commission Determination

1001. For the reasons stated in the NOPR, the Commission approves IRO–015–1 as mandatory and enforceable.

j. Coordination of Real-Time Activities Between Reliability Coordinators (IRO–016–1)

1002. IRO–016–1 establishes Requirements for coordinated real-time operations, including: (1) Notification of problems to neighboring reliability coordinators and (2) discussions and decisions for agreed-upon solutions for implementation. It also requires a reliability coordinator to maintain records of its actions.

1003. In the NOPR, the Commission proposed to approve IRO–016–1 as mandatory and enforceable.

i. Comments

1004. APPA agrees with the Commission's proposed approval of IRO–015–1 as mandatory and enforceable. However, it indicates that it is unclear in Level of Non-Compliance 2.1, how a reliability coordinator can demonstrate that it coordinated with other reliability coordinators without having retained evidence such as detailed logs or telephone recordings of having done so.[316]

ii. Commission Determination

1005. For the reasons stated in the NOPR, the Commission approves IRO–016–1 as mandatory and enforceable.

1006. We construe Level of Non-Compliance 2.1 as requiring evidence of coordination, but allowing flexibility on the type of evidence.

8. MOD: Modeling, Data, and Analysis

1007. The Modeling, Data and Analysis group of Reliability Standards is intended to standardize methodologies and system data needed for traditional transmission system operation and expansion planning, reliability assessment and the calculation of available transfer capability (ATC) in an open access environment. The 23 MOD Reliability Standards may be grouped into four distinct categories. The first category covers methodology and associated documentation, review and validation of Total Transfer Capability (TTC), ATC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) calculations.[317] The second category covers steady-state and dynamics data and models.[318] The third category

[315] *See RTO Border Utility Issues,* Notice of Technical Conference on Seams Issues for RTOs and ISOs in the Eastern Interconnections (Docket No. AD06–9–000) (issued Jan. 25, 2007).

[316] IRO–016–1 Level of Non-Compliance 2.1 states: ''For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did coordinate, but did not have evidence that it coordinated with other Reliability Coordinators.''

[317] MOD–001–0 through MOD–009–0.

[318] MOD–010–0 through MOD–015–0.

covers actual and forecast demand data.[319] The fourth category covers verification of generator real and reactive power capability.[320]

1008. In the NOPR, the Commission proposed that one out of 23 MOD Reliability Standards be approved unconditionally, nine be approved with direction for modification and 13 remain pending with direction for modification.[321] The Commission, describing these 13 pending standards as fill-in-the-blank Reliability Standards, generally proposed to seek additional information before acting on them. Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.

i. Comments

1009. ISO/RTO Council and ISO–NE agree with the Commission's proposal to neither approve nor remand the 13 MOD Reliability Standards until NERC supplies additional information. ISO/RTO Council and ISO–NE also recommend that the Commission go further and defer its approval of the MOD Reliability Standards that incorporate references to the 13 fill-in-the-blank Reliability Standards until those 13 are approved unconditionally. ISO/RTO Council and ISO–NE believe that the following Reliability Standards are dependent upon the 13 fill-in-the-blank standards: MOD–010–0, MOD–012–0, MOD–016–1, MOD–017–0, MOD–018–0, MOD–019–0, and MOD–021–0 and as such, the Commission should not approve and make them enforceable at this time. ISO–NE warns that these listed standards share the same infirmities as the 13 the Commission found it could not yet approve. ISO–NE cautions that until the missing information is provided in the 13 cross-referenced standards, it will be impossible for the affected entities to determine what criteria they are expected to satisfy.

1010. EPSA, in contrast to ISO/RTO Council and ISO–NE, expresses its concern with the Commission's proposal not to act on the 13 fill-in-the-blank standards. EPSA considers the fill-in-the-blank standards vitally important to reliability and competitive markets and worries that progress may be lost while the regions endeavor to file the additional required information.

ii. Commission Determination

1011. The Commission will adopt the NOPR proposal and retain the same disposition of the MOD Reliability Standards that it proposed there. We confirm in this Final Rule that one out of 23 MOD standards is approved unconditionally, nine are approved with direction for modification and 13 remain pending with direction for modification. We will discuss our rationale for this decision in the Commission Determination section for each particular Reliability Standard.

1012. We reject ISO/RTO Council and ISO–NE's request that we defer our approval of Reliability Standards from the MOD group that incorporate references to the 13 fill-in-the-blank standards. While we understand ISO/RTO Council and ISO–NE's concern about cross-referencing pending Reliability Standards, the data that is needed will be provided as described in the Common Issues section.[322] In the interim, compliance with the pending Reliability Standards should continue on a voluntary basis, and the Commission considers compliance with them a matter of good utility practice. The Commission believes, moreover, that the blanks will be filled in in a timely manner, since in this rule we require the ERO to develop a Work Plan and submit a compliance filing describing the process for collection of the information set forth in the deferred standards.

1013. In response to EPSA's concern that opportunities for discrimination and concerns about reliability remain while we await additional information, we emphasize that the Commission has provided specific direction regarding appropriate modifications to the MOD standards here and in Order No. 890, and has required the submission of a Work Plan for completion of that work within 90 days.[323] Moreover, the OATT and OASIS transparency reforms adopted in Order No. 890 will ensure that opportunities for discrimination will be minimized while NERC completes work on the MOD Reliability Standards.

b. MOD Standards Related to ATC, TTC, CBM and TRM

i. OATT Reform and the MOD Standards

1014. As pointed out in the NOPR, the Commission has been considering ATC, TTC, CBM and TRM calculation issues in Docket Nos. RM05–17–000 and RM05–25–000, and addressed them in Order No. 890. In order to maintain a consistent approach with regard to ATC issues, we confirm here the determinations made in Order No. 890. Each such determination is addressed below.

1015. In Order No. 890, the Commission addressed the potential for undue discrimination by requiring industry-wide consistency and transparency of all components of ATC calculation methodology and certain definitions, data and modeling assumptions. The Commission also indicated there that the lack of consistent, industry-wide ATC calculation standards poses a threat to the reliable operation of the Bulk-Power System, particularly with respect to the inability of one transmission provider to know with certainty its neighbors' system conditions affecting its own ATC values. As a result of this reliability component, the Commission asserted that the proposed ATC reforms are also supported by FPA section 215, through which the Commission has the authority to direct the ERO to submit a Reliability Standard that the Commission considers appropriate to implement FPA section 215.[324]

1016. In Order No. 890, the Commission directed public utilities, working through NERC and NAESB, to develop Reliability Standards and business practices to improve the consistency and transparency of ATC calculations. The Commission required public utilities, working through NERC, to modify the ATC-related Reliability Standards within 270 days of publication of Order No. 890 in the **Federal Register**. The Commission also directed public utilities to work through NAESB to develop business practices that complement NERC's new Reliability Standards within 360 days of publication of Order No. 890 in the **Federal Register**. Finally, the Commission directed NERC and NAESB to file a joint status report on standards and business practices development, and a Work Plan for completion of this

[319] MOD–016–0 through MOD–021–0.

[320] MOD–024–1 through MOD–025–1.

[321] Approved: MOD–018–0; approved with modification: MOD–06–0, MOD–007–0, MOD–010–0, MOD–012–0, MOD–016–1, MOD–017–0, MOD–019–0 through MOD–021–0; and pending: MOD–001–0 through MOD–005–0, MOD–08–0, MOD–09–0, MOD–011–0, MOD–013–1 through MOD–015–0, MOD–024–1 and MOD–025–1.

[322] *See* Common Issues Pertaining to Reliability Standards: Fill-in-the-Blank Standards, *supra* section II.E.5.

[323] OATT Reform Final Rule, Order No. 890, issued February 15, 2007.

[324] FPA section 215(d)(5).

task, within 90 days of publication of Order No. 890 in the **Federal Register**.

1017. The electric utility industry has also acknowledged this problem and has taken steps to address the lack of consistency and transparency in the way ATC is calculated. NERC formed a Long-Term Available Flowgate Capacity Task Force to review NERC's standards on ATC, which issued a final report in 2005.[325] Based on the recommendations in the NERC Report, NERC has begun two Standards Authorization Request proceedings to revise the standards on ATC.[326] NAESB has also begun a proceeding to develop business practice standards to enhance the processing of transmission service requests that affect ATC calculation. Following the issuance of the OATT Reform NOPR on May 19, 2006, and the Reliability Standards NOPR on October 19, 2006, NERC accelerated development of these standards in accordance with the guidelines provided in these NOPRs. NERC and NAESB representatives participated in the Commission's Technical Conference held on October 12, 2006, and informed the Commission on the status of Reliability Standards development.[327] NERC posted the Draft Standard MOD–001–1, proposing ATC/TTC/AFC (Available Flowgate Capability) revisions, on its Web site on February 15, 2007.[328]

(a) Comments

1018. EPSA commends the Commission for recognizing the direct connection between the MOD group of Reliability Standards and the initiative to reform Order No. 888 to address existing opportunities to discriminate against competitive power suppliers in access to the transmission system. TAPS and EPSA note that in both the OATT Reform NOPR and the Reliability Standards NOPR, the Commission has articulated serious concerns about the lack of clarity, transparency and uniformity in the critical calculations pertaining to one of the most fundamental aspects of the wholesale bulk power transmission system, and urge the Commission to make these calculations transparent, consistent, and better yet, regional. TAPS agrees with Staff's concerns raised in the NOPR about ATC, TTC, CBM and TRM standards. Constellation particularly supports the proposed changes to MOD–001–0, MOD–004–0, MOD–006–0 and MOD–007–0 because these Reliability Standards, as modified, will provide more information to users regarding ATC, TTC, existing transmission commitments (ETC), AFC, CBM and TRM, and that information will begin the process of providing consistent standards for their calculation.

1019. Constellation agrees with EPSA and cautions that it will take time for NERC to develop, and for the Commission to definitively approve, ATC-related standards. Constellation therefore proposes that the Commission should, upon issuance of a Final Rule, require transmission providers to post the information that the Commission directs regarding these values, even if work toward more consistency is not yet complete. Constellation believes that this will aid in ensuring that users request and receive more reliable transmission service on a nondiscriminatory basis.

1020. Contrary to the majority of commenters that support Commission action regarding ATC issues, MISO states that a Reliability Standard is not the place to address perceived comparability issues. MISO states that NERC is responsible for Reliability Standards, but not for tariffs and business practices that deal with market and equity issues.

(b) Commission Determination

1021. We agree with the many commenters that recognize the direct connection between the MOD group of Reliability Standards and available transfer capability methodologies addressed in Order No. 890, in which we developed policies to lessen, if not fully eliminate, opportunities to discriminate against competitive power suppliers in access to the transmission system.

1022. We recognize the concerns raised by EPSA and Constellation that opportunities for discrimination and related reliability concerns may remain during the interim Reliability Standards modification process, in part because of the discretion that transmission service providers will retain in calculating ATC values. We point out, however, that all transmission providers are required to file a modified Attachment C to their OATTs detailing their ATC calculation methodologies in advance of the development of the new Reliability Standards. All transmission providers are required to comply with their OATTs, and are subject to the filing of a complaint or Commission-initiated enforcement action if discrimination occurs. Regarding Constellation's recommendation that the Commission act in advance, and require transmission service providers to post the information that the Commission directs regarding ATC values, even if work toward more consistency is not yet complete, we clarify that we will require transmission service providers to comply with existing ATC-related posting obligations on OASIS as supplemented by Order No. 890. These requirements are not subject to standardization by the ERO, and will be effective in accordance with the timeline stated in Order No. 890.

1023. We disagree with MISO's contention that the Reliability Standards are an inappropriate venue for addressing ATC comparability issues. ATC raises both comparability and reliability issues, and it would be irresponsible to take action under FPA section 206 to require consistency in ATC calculations without considering the reliability impact of those decisions. Therefore, the Commission in Order No. 890 provided direction to public utilities, working through NERC and NAESB, regarding development of the ATC-related Reliability Standards and business practices, and we repeat that direction here.

c. Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies (MOD–001–0)

1024. The purpose of MOD–001–0 is to promote the consistent and uniform application of transfer capability calculations among transmission system users. The Reliability Standard requires each regional reliability organization to develop a regional TTC and ATC methodology in conjunction with its members and to post the most recent version of its TTC and ATC methodologies on a Web site accessible by NERC, the regional reliability organization, and transmission users.

1025. In the NOPR, the Commission identified MOD–001–0 as a fill-in-the-

[325] The NERC Report made recommendations for greater consistency and greater clarity in the calculation of ATC/AFC. The task force also recommended greater communication and coordination of ATC/AFC information to ensure that neighboring entities exchange relevant information. *See* NERC, *Long-Term AFC/ATC Task Force Final Report* (2005) (NERC Report) at 2, available at: *fttp://www.nerc.com/pub/sys/all_updl/mc/ltatf/LTATF_Final_Report_Revised.pdf.*

[326] The first SAR proceeding proposes changes to the existing standards on ATC to, among other things, further establish consistency in the calculation of ATC and to increase the clarity of each transmission provider's ATC calculation methodology. The second SAR proceeding proposes certain changes to NERC's existing CBM and TRM standards and calls for greater regional consistency and transparency in how CBM and TRM are treated in transmission providers' ATC calculations.

[327] Technical Conference regarding Preventing Undue Discrimination and Preference in Transmission Service under RM05–25 *et al.* (October 12, 2006).

[328] That posting preceded by one day the issuance of Order No. 890. Therefore, the posted draft Standard MOD–001–1 does not reflect the requirements of Order No. 890, but rather is guided by the NOPR issued in the OATT Reform and Reliability Standards proceedings.

blank standard that requires each regional reliability organization to develop its respective methods for determining TTC and ATC and to make those methodologies available to others for review. The NOPR stated that the Commission would not propose to approve or remand MOD–001–0 until the ERO submits additional information.

1026. Although the Commission did not propose any action with regard to MOD–001–0, it addressed a number of concerns regarding the Reliability Standard, consistent with those proposed in the OATT Reform NOPR. The Commission proposed that this standard should: (1) At a minimum, provide a framework for ATC, TTC and ETC calculation; (2) require disclosure of algorithms and processes used in ATC calculation; (3) identify a detailed list of information to be exchanged among transmission providers for the purposes of ATC modeling; (4) include requirements that the assumptions used in ATC and AFC calculations be consistent with those used for planning expansion or operation of the Bulk-Power System to the maximum extent practicable; [329] (5) include a requirement that applicable entities make available assumptions and contingencies underlying ATC and TTC calculations; (6) address only ATC while the TTC should be addressed under FAC–012–1; and (7) identify to whom MOD–001–0 standards apply, *i.e.*, users, owners and operators of the Bulk-Power System.[330] We will discuss the comments and Commission conclusions for each of these modifications separately below.

i. Comments

1027. APPA agrees with the Commission that MOD–001–0 in its current form is a fill-in-the-blank standard, is not sufficient in its current form and should not be accepted for approval as a mandatory Reliability Standard until the accompanying regional procedures are submitted and approved.

ii. Commission Determination

1028. The Commission adopts the NOPR proposal not to approve or remand MOD–001–0 until the ERO submits additional information. Consistent with Order No. 890, and comments received in response to the NOPR, the Commission directs the ERO to consider modifications of MOD–001–0 through the Reliability Standards development process as discussed below.

iii. Provide a Framework for ATC, TTC and ETC Calculation

(a) Comments

1029. APPA supports the Commission's proposal that NERC modify MOD–001–0 to, at a minimum, provide a framework for ATC, TTC and ETC calculation.

(b) Commission Determination

1030. We continue to believe that MOD–001–0 should, at a minimum, provide a framework for ATC, TTC and ETC calculations. This framework should consider industry-wide consistency of all ATC components and certain data inputs and exchange, modeling assumptions, calculation frequency, and coordination of data relevant for the calculation of ATC. Consistent with Order No. 890, we do not require a single computational process for calculating ATC for several reasons. First, it is not our intent to require transmission providers to incur the expense of developing and adopting a new one-size-fits-all software package to calculate ATC without proven benefits. More importantly, we find that the potential for discrimination and decline in reliability level does not lie primarily in the choice of an ATC calculation methodology, but rather in the consistent application of its components, and input and exchange data, along with modeling assumptions. Consistent and transparent ATC calculation will provide equivalent results between regions and will therefore prevent transmission service providers from overselling transfer capability that can stress conditions on their own and adjacent systems, and jeopardize reliability. In addition, we are especially concerned with the lack of data exchange between neighboring transmission service providers, which is a prerequisite for accurate calculation of ATC.

1031. The Commission understands that the ERO currently is developing three ATC calculation methodologies (contract or rating path ATC, network ATC, and network AFC).[331] If all of the ATC components, and certain data inputs and assumptions are consistent, the three ATC calculation methodologies will produce predictable and sufficiently accurate, consistent, equivalent and replicable results. It is therefore not necessary to require a single industry-wide ATC calculation methodology.

1032. In addition, consistent with Order No. 890, we note that there is neither a definition of AFC/TFC (Total Flowgate Capability) in the ERO's glossary nor an existing Reliability Standard that discusses AFC. Consistent with our approach to achieving consistency and transparency, we direct the ERO to develop AFC/TFC definitions and requirements used to identify a particular set of transmission facilities as flowgates. We extend the same requirements for industry-wide consistency of all AFC components and certain data inputs and exchange, modeling assumptions, calculation frequency, and coordination of data relevant for the calculation of AFC as we stated above for ATC. However, we remind transmission providers that our regulations require the posting of ATC values associated with a particular path, not AFC values associated with a flowgate. Accordingly, transmission providers using an AFC methodology must convert flowgate (AFC) values into path (ATC) values for OASIS posting. In order to display consistent posting of ATC and TTC values on OASIS, we direct the ERO to develop a Requirement in the Reliability Standard for conversion of AFC into ATC values for use by transmission providers that currently apply flowgate methodology.

1033. We underscore Order No. 890's objective of greater consistency in ETC calculations. The Commission directs the ERO to develop a consistent approach for determining the amount of transfer capability a transmission provider may set aside for its native load and other committed uses. We expect that the ERO will address ETC through the MOD–001–0 Reliability Standard rather than through a separate Reliability Standard. By using MOD–001–0, the ETC calculation principles can be adjusted to apply to each of the three ATC methodologies being developed by the ERO. In order to provide specific direction to public utilities and the ERO, we determine that

[329] NOPR at P 609.

[330] *Id.* at P 610. We note that our observation regarding applicable entities here also applies to MOD–002–0, MOD–003–0, MOD–004–0, MOD–005–0, MOD–008–0, MOD–009–0, MOD–011–0, MOD–013–0, MOD–014–0, MOD–015–0, MOD–016–0, MOD–024–0 and MOD–025–0.

[331] October 12, 2006 Technical Conference regarding Preventing Undue Discrimination and Preference in Transmission Service under RM05–25 et al. These three methodologies are different computational processes to determine a transmission system's ATC. The first, contract path, examines TTC for every A-to-B path on the system in concert with all others, reduces ATC by path for ETC, TRM and CBM, as appropriate, and produces ATC for each path. The second method, network ATC, uses a simulator to look not at each path, but at each transmission element (line, substation, etc.) and run first contingency simulations to establish ATC on a network basis, rather than a path basis. The third method, network AFC, uses a simulator to examine critical flowgates over a wider area, then requires a second step to convert AFC values to particular path ATC values.

ETC should be defined to include committed uses of the transmission system, including: (1) Native load commitments (including network service); (2) grandfathered transmission rights; (3) firm and non-firm point-to-point reservations; (4) rollover rights associated with long-term firm service and (5) other uses identified through the ERO process. ETC should not be used to set aside transfer capability for any type of planning or contingency reserve; these are to be addressed through CBM and TRM.[332] In addition, in the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) must be released as non-firm ATC.

1034. We reiterate the finding in Order No. 890 that including all requests for transmission service in ETC is likely to overstate usage of the system and understate ATC. Accordingly, we find that reservations that have the same point of receipt (POR) (generator) but different point of delivery (POD) (load), for the same time frame, should not be modeled in the ETC calculation simultaneously if their combined reserved transmission capacity exceeds the generator's nameplate capacity at a POR. This will prevent unrealistic use of transmission capacity associated with power output from a generator identified as a POR. One approach that could be used is examining historical patterns of actual reservation use during a particular season, month, or time of day.

1035. In summary, we direct the ERO to modify MOD–001–0 to provide a framework for ATC, TTC and ETC calculation that, consistent with the discussion above: (1) Requires industry-wide consistency of all ATC components and certain data inputs and exchange, modeling assumptions, calculation frequency, and coordination of data relevant for the calculation of ATC; (2) provides predictable and sufficiently accurate, consistent, equivalent, and replicable ATC calculations regardless of the methodology used by the region; (3) provides the definition of AFC and method for its conversion to ATC; (4) lays out clear instructions on how ETC should be defined and (5) identifies to whom MOD–001–0 Reliability Standards apply, *i.e.*, users, owners and operators of the Bulk-Power System.

[332] TRM also includes such things as loop flow and parallel path flow.

iv. Require Disclosure of Algorithms and Processes Used in ATC Calculation

(a) Comments

1036. APPA supports the Commission's proposal that NERC modify MOD–001–0 to require documentation including mathematical algorithms, process flow diagrams, data inputs and identification of flowgates.

(b) Commission Determination

1037. The Commission adopts the proposal from the NOPR to direct the ERO to modify Reliability Standard MOD–001–0 to require disclosure of the algorithms and processes used in ATC calculation. In addition, consistent with Order No. 890, the Commission believes that further clarification is necessary regarding the ATC calculation algorithm for firm and non-firm ATC.[333] Currently, the ERO has no specifications for calculating non-firm ATC. We find that the same potential for discrimination exists for non-firm transmission service as for firm service, and greater uniformity in both firm and non-firm ATC calculations will substantially reduce the remaining potential for undue discrimination. Therefore, we direct the ERO to modify Reliability Standard MOD–001–0 to require disclosure of the algorithms and processes used in ATC calculation, and also to implement the following principles for firm and non-firm ATC calculations: (1) For firm ATC calculations, the transmission provider shall account only for firm commitments and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, postbacks of redirected service, unscheduled service and counterflows.

v. Identify a Detailed List of Information To Be Exchanged Among Transmission Providers for the Purposes of ATC Modeling

(a) Comments

1038. APPA supports the Commission's proposal that NERC modify MOD–001–0 to require applicable entities to identify a detailed list of information to be shared.

[333] The NERC ATC definition does not differentiate firm and non-firm ATC from the following high level generic ATC definition: A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.

(b) Commission Determination

1039. The Commission adopts the NOPR proposal and reiterates the requirement in Order No. 890 that the ERO must revise the MOD Reliability Standards to require the exchange of data and coordination among transmission providers. We direct the ERO to modify MOD–001–0 to ensure that the following data, at a minimum, be exchanged among transmission providers for the purposes of ATC modeling: (1) Load levels; (2) transmission planned and contingency outages; (3) generation planned and contingency outages; (4) base generation dispatch; (5) existing transmission reservations, including counterflows; (6) ATC recalculation frequency and times and (7) source/sink modeling identification.[334] The Commission concludes that the exchange of such data is necessary to support the reforms requiring consistency in the determination of ATC adopted in this Final Rule. As explained above, transmission providers are required to coordinate the calculation of TTC/TFC and ATC/AFC with others, and this requires a standard means of exchanging data.

vi. Include Requirements That the Assumptions Used in ATC and AFC Calculations Should Be Consistent, to the Maximum Extent Practicable, With Those Used for Planning the Expansion or Operation of the Bulk-Power System

(a) Commission Determination

1040. The Commission adopts the NOPR's proposal to require transmission providers to use data and modeling assumptions for short- and long-term ATC calculations that are consistent with those used for the planning of operations and system expansion, to the maximum extent practicable. This includes, for example: (1) Load levels; (2) generation dispatch; (3) transmission and generation facilities maintenance schedules; (4) contingency outages; (5) topology; (6) transmission reservations; (7) assumptions regarding transmission and generation facility additions and retirements and (8) counterflows, which must be the same in the models used in the transmission operational and planning studies performed for the transmission providers' native load. We find that requiring consistency in the data and modeling assumptions used for ATC calculation will remedy the potential for undue discrimination by eliminating discretion and ensuring comparability in the manner in which a

[334] NOPR at P 169.

transmission provider operates and plans its system to serve native load, and the manner in which it calculates ATC for service to third parties.

1041. We clarify that we require consistent use of assumptions underlying operational planning for short-term ATC and expansion planning for long-term ATC calculation. We also clarify that there must be a consistent basis for or approach to determining load levels in each of these sets of calculations. For example, one approach may be for transmission providers to calculate load levels using an on- and off-peak model for each month when evaluating yearly service requests and calculating yearly ATC. The same (peak- and off-peak) or alternative approaches may be used for monthly, weekly, daily and hourly ATC calculations. Regardless of the ultimate choice, it is imperative that all transmission providers use the same approach to modeling load levels to eliminate undue discrimination and enable the meaningful exchange of data among transmission providers. Accordingly, we direct the ERO to develop consistent requirements for modeling load levels in MOD–001–0.

1042. With respect to modeling of generation dispatch, we direct the ERO to develop requirements in MOD–001–0 specifying how transmission providers should determine which generators should be modeled in service, including guidance on how independent generation should be considered. Accordingly, we direct the ERO to revise Reliability Standard MOD–001–0 by specifying that base generation dispatch will model: (1) All designated network resources and other resources that are committed to or have the legal obligation to run, as they are expected to run and (2) all uncommitted resources that are deliverable within the control area, economically dispatched as necessary to meet balancing requirements.

1043. Regarding transmission reservations modeling, we direct the ERO to develop requirements in Reliability Standard MOD–001–0 that specify: (1) A consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations.

1044. Consistent with Order No. 890, the Commission directs the ERO to modify Reliability Standard MOD–001–0 to require ATC to be updated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, *e.g.*, generation and transmission outages, load forecasts, interchange schedules, transmission reservations, facility ratings and other necessary data. This process must also consider whether ATC should be calculated more frequently for constrained facilities.

1045. In conclusion, we direct the ERO to modify MOD–001–0 to require that: (1) Assumptions used for short-term ATC calculations be consistent with those used for operation planning to the maximum extent practicable; (2) assumptions used for long-term ATC calculations be consistent with those used for system planning to the maximum extent practicable and (3) ATC be updated by all transmission providers on a consistent time interval.

vii. Include a Requirement That Applicable Entities Make Available Assumptions and Contingencies Underlying ATC and TTC Calculations

(a) Comments

1046. APPA supports the Commission's proposal that NERC modify MOD–001–0 to include a requirement that applicable entities make available a comprehensive list of assumptions and contingencies underlying ATC and TTC calculations.

(b) Commission Determination

1047. We adopt the NOPR's proposal that this Reliability Standard should include a requirement that applicable entities make available a comprehensive list of assumptions and contingencies underlying ATC/AFC and TTC/TFC calculations. While we require the submission of contingency files under MOD–010–0, here we only direct the ERO to consider development of a requirement that the transmission service provider declare what type of contingencies it uses for specific calculations of ATC/AFC and TTC/TFC, and release the contingency files upon request if not submitted with the data filed with the ERO in compliance with MOD–010–0.

1048. In order to increase the transparency of ATC calculations, we adopt the NOPR's proposal and direct the ERO to develop in MOD–001–0 a requirement that each transmission service provider provide on OASIS its OATT Attachment C, in which Order No. 890 requires transmission providers to include a detailed description of the specific mathematical algorithm the transmission provider uses to calculate both firm and non-firm ATC for various time frames such as: (1) The scheduling horizon (same day and real-time), (2) operating horizon (day ahead and pre-schedule) and (3) planning horizon (beyond the operating horizon). In addition, a transmission provider must include a process flow diagram that describes the various steps that it takes in performing the ATC calculation.

viii. Address Only ATC While TTC Should Be Addressed Under FAC–012–1

(a) Comments

1049. APPA concurs with the NOPR's proposal that TTC should be standardized under FAC–012–1, and that there appears to be little or no distinction between the definitions for TTC (MOD–001–0) and TC (FAC–012–1). APPA anticipates that this distinction will either be clarified or eliminated through ongoing Reliability Standards development activity.

1050. Conversely, MidAmerican notes that the transfer capability covered by FAC–012–1 may not relate to the TTC that is the subject of the MOD–001–0 standard. MidAmerican opines that the purpose of the FAC–012–1 standard is to ensure that each reliability coordinator and planning authority documents the methodology used to develop inter- and intra-regional transfer capabilities used in the reliable planning and operation of the Bulk-Electric System. MidAmerican further details that transfer capabilities that are covered by FAC–012–1 could be used by a reliability coordinator to operate the system in a temporary situation or by the planning authority as the basis for a sensitivity case. It adds that in neither of these cases would these transfer capabilities necessarily be included in calculations for ATC that would be used for offering transmission capacity for sale.

(b) Commission Determination

1051. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC–012–1, rather than MOD–001–0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC–008–1 provides the basis for determining the thermal ratings of facilities while FAC–009–1 provides the basis for communicating those ratings. FAC–010–1 and FAC–011–1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC–014 provides for the communication of those ratings.[335]

[335] FAC–010, FAC–011, and FAC–014 are addressed in Docket No. RM07–03 because they were submitted later than the original 107

1052. The Commission directs the ERO, through the Reliability Standards development process, to modify FAC–012–1 and any other appropriate Reliability Standards to assure consistency in the determination of TTC/TFC for services provided under the *pro forma* OATT, and requires that those processes be the same as those used in operation and planning for native load and reliability assessment studies. Changes to the process of calculating TTC are appropriate if implementation is coordinated with revisions to the other applicable operating or planning standards. We acknowledge that reliability regions have historically calculated transfer capability using different approaches, and we agree that regional differences should be respected.[336] However, as already discussed above regarding ATC, TTC requirements will be determined in the ERO Reliability Standards development process, and any request for a regional difference from the Reliability Standards must take place through the ERO process.

1053. We disagree with MidAmerican's opinion that transfer capabilities that are addressed by FAC–012–1 are necessarily different from TTC used for ATC calculation. The NERC glossary defines transfer capability (TC) [337] as essentially identical to TTC.[338] We believe that modeling principles for simulating power transfers and determination of transfer capabilities should be the subject of a single standard. Those principles should be the same regardless of whether transfer capability is used for the purpose of operations, planning or offering for sale. By modeling principles we refer to the way transfers are simulated and the type of analysis that should be performed, such as steady-state, dynamic stability or voltage stability. We are certain that consistent calculation of transfer capabilities will prevent over- and under-estimation of the total transfer capability available for sale. We agree with APPA that this distinction should either be clarified or eliminated through the ongoing Reliability Standards development process, and therefore direct the ERO to modify MOD–001–0 to address TTC under transfer capability-related standards such as the FAC group of Reliability Standards.

ix. Identify the Entities To Whom the MOD Standards Apply

(a) Comments

1054. APPA agrees in part with the Commission's conclusion that ''NERC should identify the applicable entities in terms of users, owners and operators of the Bulk-Power Systems.'' [339] APPA, however, is concerned that this approach may confuse rather than clarify compliance responsibilities. According to APPA, a regional organization in conjunction with entities that plan, own, operate (and use) transmission facilities within each region must be involved in the development of any regional TTC and ATC methodology. In this context, APPA views the ''regional reliability organization'' as the technical arm of the reliability region, made up of the various committees whose members are users, owners and operators of the Bulk-Power System, along with support from the regional reliability organization staff. Further, APPA notes that ultimately, it is these core users, owners and operators of the Bulk-Power System that are responsible for the development of and adherence to the ATC methodology, and that the regional reliability organization, as an organization, is responsible for ensuring that the methodology is developed (under R1) and publicly posted (under R2).

1055. In addition, APPA states that under the statutory framework established in FPA section 215, as interpreted by the Commission in Order No. 672, it is clear that the compliance monitor within each region is the Regional Entity, and the Regional Entity is not a user, owner or operator of the Bulk-Power System. APPA notes that while regional delegation agreements may be used to impose certain reliability compliance functions upon Regional Entities and their affiliates, no Regional Entity should be charged with enforcing compliance against itself. Ultimately, APPA is concerned that the quality of regional modeling and technical assessments will be diminished if the collaborative efforts used for the past 50 years of interconnected operations are displaced due to pressures to identify a single entity or class of entities with direct compliance responsibilities for regional modeling standards. APPA states that identifying all users, owners and operators as responsible entities does not answer the question either. APPA expresses its intention that it will work with NERC and with other stakeholders to ensure that this industry-based expertise is maintained and enhanced, while ensuring that responsible entities are identified in this and other NERC standards.

(b) Commission Determination

1056. APPA is suggesting that respective regional organizations, their technical staff, and committees of users, owners and operators of the Bulk-Power System be charged with developing the methodologies. We disagree. These Reliability Standards should be developed through the Commission-approved Reliability Standards development process which will identify the entities that should implement the Reliability Standards, the Requirements necessary to achieve the goals identified in Order No. 890, and the Measures necessary to monitor compliance.

1057. The Commission agrees with APPA that the collaborative efforts and knowledge developed over decades of interconnected operation should not be wasted. We do not believe that will happen through the Reliability Standards development process and that all of the applicable entities will have significant roles to play in achieving the goal the Commission has set out in Order No. 890. Therefore, we adopt the proposal in the NOPR and direct the ERO to modify MOD–001–0 to reflect the users, owners and operators to which the Reliability Standard will apply.

x. Summary of Commission Determination

1058. Accordingly, the Commission neither accepts nor remands MOD–001–0 until the ERO submits additional information. Although the Commission does not propose any action with regard to MOD–001–0, we address above a number of concerns regarding the Reliability Standard, consistent with those set forth in Order No. 890. We direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process that: (1) Provide a framework for ATC, TTC and ETC calculation,

Reliability Standards and we did not have sufficient time to allow appropriate review and comment.

[336] For example, WECC has a documented open process for establishing TTC for the Western Interconnection.

[337] Transfer Capability is defined in the NERC glossary as ''[t]he measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from 'Area A' to 'Area B' is not generally equal to the transfer capability from 'Area B' to 'Area A.' '' NERC Glossary at 18.

[338] Total Transfer Capability is defined in the NERC glossary as ''[t]he 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.'' *Id.*

[339] NOPR at P 610.

developing industry-wide consistency of all ATC components; (2) require disclosure of algorithms, for both firm and non-firm ATC and processes used in the ATC calculation; (3) identify a detailed list of information to be exchanged among transmission providers for the purposes of ATC modeling; (4) include a requirement that the assumptions used in ATC and AFC calculations should be consistent with those used for planning the expansion or operation of the Bulk-Power System to the maximum extent practicable; (5) include a requirement that ATC be updated by all transmission providers on a consistent time interval; (6) include a requirement that applicable entities make available assumptions and contingencies underlying ATC and TTC calculations; (7) address only ATC/AFC while TTC/TFC should be addressed under transfer capability standards such as FAC–012–1 and (8) identify the applicable entities in terms of users, owners and operators of the Bulk-Power System.

d. Review of Transmission Service Provider Total Transfer Capability and Available Transfer Capability Calculations and Results (MOD–002–0)

1059. MOD–002–0 concerns the review of transmission service providers' compliance with the regional methodologies for calculating TTC and ATC. It requires that the regional reliability organization: (1) Develop and implement a procedure to periodically review and ensure that the TTC and ATC calculations and resulting values developed by transmission service providers comply with the regional TTC and ATC methodology and applicable regional criteria; (2) document the results of its periodic review and (3) provide the results of its most current reviews to NERC upon request.

1060. In the NOPR, the Commission identified MOD–002–0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and implement a procedure to periodically review and ensure that a transmission service provider's TTC and ATC calculations comply with regional TTC and ATC methodologies and criteria. The NOPR stated that the Commission would not propose to approve or remand MOD–002–0 until the ERO submits additional information.

i. Comments

1061. APPA agrees that MOD–002–0 is a fill-in-the-blank standard. It is not sufficient in its current form and should not be approved as a mandatory Reliability Standard until the accompanying regional procedures are submitted and approved.

ii. Commission Determination

1062. The Commission adopts the NOPR proposal not to approve or remand MOD–002–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–002–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' Accordingly, the Commission neither approves nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD–002–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

e. Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values (MOD–003–0)

1063. MOD–003–0 requires each regional reliability organization to: (1) Develop and document a procedure on how a transmission user can present its concerns or questions regarding TTC and ATC calculations including the TTC and ATC values, and how these concerns will be addressed and (2) make its procedure for receiving and addressing these concerns available to other regional reliability organizations, NERC and transmission users on its Web site.

1064. In the NOPR, the Commission identified MOD–003–0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and document a procedure on how a transmission user can present its concerns regarding the TTC and ATC methodologies of a transmission service provider. The NOPR stated that the Commission would not propose to approve or remand MOD–003–0 until the ERO submits additional information.

i. Comments

1065. APPA agrees that MOD–003–0 is a fill-in-the-blank standard. It notes that it is not sufficient in its current form and should not be approved as a mandatory Reliability Standard until the accompanying regional procedures are submitted and approved. In addition, APPA hopes that if NERC develops the MOD–001–0 Reliability Standard properly, it will include a reporting procedure for addressing shortcomings in information for all transmission customers (LSE, generator owner and purchasing-selling entity) in the MOD–001–0 Standard. APPA argues that, as a result, MOD–003–0 may be redundant and should be eliminated.

ii. Commission Determination

1066. The Commission adopts the NOPR proposal not to approve or remand MOD–003–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–003–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' Accordingly, the Commission neither accepts nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD–003–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

1067. We direct the ERO to consider APPA's suggestion that MOD–003–0 may be redundant and should be eliminated if the ERO develops a modification to the MOD–001–0 Reliability Standard through the Reliability Standards development process that includes reporting requirements.

f. Documentation of Regional Reliability Organization Capacity Benefit Margin Methodologies (MOD–004–0)

1068. MOD–004–0 requires each regional reliability organization to: (1) Develop and document a regional CBM [340] methodology in conjunction with its members and (2) post the most recent version of its CBM methodology on a Web site accessible by NERC, regional reliability organizations and transmission users.

1069. In the NOPR, the Commission identified MOD–004–0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and document a regional CBM methodology. The NOPR stated that because the regional CBM methodologies had not been submitted, the Commission would not propose to

[340] The NERC glossary defines ''capacity benefit margin'' or ''CBM'' as the amount of firm transmission transfer capability preserved by a transmission provider for load serving entities whose loads are located on the transmission service provider's system, to enable access by the load serving entity to generation from interconnected systems to meet generation reliability requirements. NERC Glossary at 2.

approve or remand MOD–004–0 until the ERO submits the additional information.

1070. Although not proposing any action, the Commission nonetheless indicated that MOD–004–0 could be improved by: (1) Providing more specific requirements on how CBM should be determined and allocated to interfaces and (2) including a provision ensuring that CBM, TRM and ETC cannot be used for the same purpose, such as the loss of an identical generation unit. Further, the Commission expressed concern that the Reliability Standard may unduly impact competition because of the lack of consistent criteria and clarity with regard to the entity on whose behalf CBM has been set aside. This lack of consistent criteria has the potential to result in the transmission provider's setting aside capacity that it might not otherwise need to set aside, thus increasing costs for native load customers and blocking third party uses of the transmission system.

i. Comments

1071. APPA agrees with the Commission that MOD–004–0 should not be approved as a mandatory Reliability Standard until the relevant regional procedures are submitted and approved.[341]

1072. FirstEnergy states that transmission capacity margins such as CBM and TRM are vitally important to the reliability of the system, and any methodology that would unduly limit these margins could create a danger of limiting transmission capacity over interconnected facilities that would limit the ability of balancing authorities and others to obtain generation reserves needed from the grid during contingency events. In contrast, TAPS questions how TRM or, especially, CBM, can be viewed as Reliability Standards if they are optional for the transmission provider.

1073. MidAmerican supports greater uniformity of CBM definitions and calculations and states that the revised standard and/or new standards should support transparency and uniformity by encouraging increased availability of information and consistent data input and modeling assumptions. EEI emphasizes that additional data and information-sharing requirements would improve the transparency of various calculations and assumptions related to CBM, including this standard and the other CBM-related standards. EEI believes that, similar to the peer review processes of the planning studies carried out under the TPL standards, industry participants are best suited to developing the totality of assumptions, system conditions and other input variables that support the calculations.

1074. EEI notes that, with respect to the Commission's particular concern about criteria in determining resources and loads used in the CBM methodology, NERC's ''ATC Definitions and Determination'' [342] document clearly delineates the purpose and intent of the calculation of CBM and TRM. EEI states that CBM is intended to provide generation reliability, and TRM is intended to provide transmission reliability. EEI believes that, to the extent capacity capable of supplying CBM is located in the vicinity of the designated facility experiencing an outage, transmission may or may not be available under the native load reservation normally used for the facility. Therefore, EEI argues, CBM may be needed on an interface where capacity is available for use as CBM, and not allowing all generation to be considered in this manner may unduly increase the generation reserve requirement within the transmission provider's system.

1075. EEI agrees with the Commission's concern about double-counting TRM for those transmission providers who do not opt to use CBM. However, EEI argues that for transmission providers who do opt to use CBM, it may be appropriate in some circumstances to use the same generation unit outage to determine the impact on both generation and transmission reliability because the impacts are different. EEI cautions that artificially restricting such use is not appropriate, especially before NERC's development of TRM and CBM standards and their presentation to FERC through the Reliability Standards development process. EEI recommends that the Commission encourage transmission providers to make CBM and TRM capacity available to wholesale markets for purchase on a non-firm basis, because doing so would ensure that both CBM and TRM capacity are available to the transmission provider during system emergencies, as intended. EEI notes that at other times the transfer capability associated with TRM and CBM would be available to the market, alleviating the concern of possible double-counting. MidAmerican also supports the Commission's conclusion that double-counting would be inappropriate, although MidAmerican states that it is not aware of any cases of double-counting of margins.

1076. TAPS notes the significant potential for abuse [343] that could result from the current flexibility afforded transmission providers in the calculation of CBM and TRM, and proposes innovative approaches [344] to take CBM and (to the extent it is intended to cover transmission required for reserve sharing) TRM out of the hands of individual transmission providers, and to therefore reduce the opportunity for abuse.

ii. Commission Determination

1077. The Commission adopts the NOPR proposal not to approve or remand MOD–004–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–004–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' Accordingly, the Commission neither accepts nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD–004–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Consistent with Order No. 890 and comments received in response to the NOPR, the Commission directs the ERO, through the Reliability Standards development process, to modify MOD–004–0 as discussed below.

1078. We agree with FirstEnergy that CBM is important for system reliability by allowing the LSEs to meet their historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. We agree with EEI and MidAmerican that transparency of the studies supporting CBM determination will reduce the opportunity for transmission service providers to overestimate the amount of CBM and misuse transfer capability. We therefore direct the ERO to develop Requirements

[341] APPA notes that it has expressed its own concerns with CBM calculations and set-asides in its August 7, 2006 Initial Comments filed in Docket No. RM05–25–000, at 31–55. APPA is hopeful these concerns can be addressed through NERC's Reliability Standards development process.

[342] NERC, Available Transfer Capability Definitions and Determination—A Framework for Determining Available Transfer Capabilities of the Interconnected Transmission Networks for a Commercially Viable Electricity Market (June 1996).

[343] Documented by NERC's April 14, 2005 Long-Term AFC/ATC Task Force Final Report.

[344] TAPS refers the Commission to its August 7, 2006 comments in Docket No. RM05–25–000 at 21–24.

regarding transparency of the generation planning studies used to determine CBM values. We also clarify that CBM should only be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. We expect verification of the CBM values to be part of the Requirements with appropriate Measures and Levels of Non-Compliance.

1079. We continue to believe this Reliability Standard should be modified to include a provision ensuring that CBM, TRM and ETC cannot be used for the same purpose, such as loss of the identical generating unit. In order to limit misuse of transfer capability set aside as CBM, we direct the ERO to provide more specific requirements for how CBM should be determined and allocated across transmission paths or flowgates. As we stated in Order No. 890, we do not mandate a particular methodology for allocating CBM to paths or flowgates. For example, one approach could be based on the location of the outside resources or spot market hubs that a LSE has historically relied on during emergencies resulting from an energy deficiency, but we agree with EEI that flexible rules should be allowed to prevent unnecessary increase of the generation reserve requirement within the transmission provider's system. Therefore, we support flexibility, but expect that the ERO, using its Reliability Standards development process, will adequately approach these complex technical issues and propose a new version of MOD–004–0 that addresses the methods for CBM determination and allocation on paths that will reduce reliability and discrimination concerns.

1080. In response to TAPS's question asking how CBM can be viewed as a Reliability Standard if it is optional to the transmission provider, our understanding is that transmission providers that have opted not to use CBM have instead set aside transmission margin (needed to bring in outside power to meet generation reliability criteria) either through ETC or TRM. CBM is not the only way to reserve transmission capacity for a margin. However, if the Reliability Standard is not clear regarding the method of calculating transmission margins, it may cause double-counting of transmission margins and reduction of ATC. As we stated in Order No. 890, we find that clear specification of the permitted purposes for which entities may reserve CBM and TRM will virtually eliminate double-counting of TRM and CBM. Therefore, we direct the ERO to modify its standard in order to prevent setting aside transfer capability for the same purposes.

1081. We share TAPS's concern that there is a significant potential for abuse as a result of the current flexibility afforded to transmission providers in the calculation of both CBM and TRM. In response to TAPS's concern, we clarify that in accordance with the OATT Reform Final Rule and the ERO CBM definition, each LSE has the right to request CBM be set aside and use it to meet its verifiable historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. As such, the LSEs that request CBM be set aside must be identified as applicable entities with identified Requirements, including Requirements on generation studies to verify the set aside, Measures and Levels of Non-Compliance. We direct the ERO to modify the Reliability Standard accordingly.

1082. We agree with TAPS that there is a need for clearer requirements in the standard regarding to whom and how to submit a request for CBM set-aside, and what the transmission service provider should do if the sum of all CBM requirements exceeds the amount of available transfer capability. We direct the ERO to address the reliability aspects in the Reliability Standards development process and explore with NAESB whether business practices would be required.

1083. Accordingly, the Commission neither accepts nor remands MOD–004–0 until the ERO submits additional information. In the interim, compliance with MOD–004–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission did not propose any action with regard to MOD–004–0, it addressed above a number of concerns regarding the Reliability Standard, consistent with those set forth in Order No. 890. Therefore, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process to: (1) Clarify that CBM shall be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria; (2) develop requirements regarding transparency of the generation planning studies used to determine CBM value; (3) modify the current Requirements to make clear the process for how CBM is allocated across transmission paths or flowgates; (3) modify its standard in order to prevent setting aside CBM and TRM for the same purposes; (4) modify the standard by adding LSE as an applicable entity and (5) coordinate with NAESB business practice standards.

1084. We direct the ERO to consider APPA's suggestion that MOD–004–0 may be redundant and should be eliminated if the ERO develops a modification to the MOD–002–0 Reliability Standard that includes reporting requirements

g. Procedure for Verifying Capacity Benefit Margin Values (MOD–005–1)

1085. MOD–005–1 specifies the requirements regarding the periodic review of a transmission service provider's adherence to the regional reliability organization's CBM methodology. It requires each regional reliability organization to: (1) Develop and implement a procedure to review at least annually the CBM calculations and the resulting values determined by member transmission service providers; (2) document its CBM review procedure and (3) make the results of the most current CBM review available to NERC upon request.

1086. In the NOPR, the Commission identified MOD–005–0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and implement a procedure to review CBM calculations and the resulting values and to make the documentation of the results of the CBM review available to NERC and others. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD–005–0 until the ERO submits the additional information.

i. Comments

1087. APPA agrees that MOD–005–0 is a fill-in-the blank standard, and that in its current form, it is not sufficient and should not be accepted for approval as a mandatory Reliability Standard until the necessary regional procedures have been submitted and approved. APPA suggests that NERC modify MOD–006–0, so that MOD–004–0 and MOD–005–0 could be eliminated.

ii. Commission Determination

1088. The Commission adopts the NOPR proposal not to approve or remand MOD–005–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–005–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just,

reasonable, not unduly discriminatory or preferential, and in the public interest.'' Accordingly, the Commission neither accepts nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD–005–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

1089. As to APPA's comment on incorporating MOD–004 and MOD–005 into MOD–006, we direct the ERO to consider those comments through the Reliability Standards development process.

h. Procedure for Use of Capacity Benefit Margin Values (MOD–006–0)

1090. The purpose of MOD–006–0 is to promote the consistent and uniform use of transmission CBM calculations among transmission system users. MOD–006–0 requires that each transmission service provider document its procedure for the scheduling of energy against a CBM reservation and make the procedure available on a Web site accessible by the regional reliability organization, NERC and transmission users.

1091. In the NOPR, the Commission proposed to approve Reliability Standard MOD–006–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–006–0 that: (1) Includes a provision that will ensure that CBM and TRM are not used for the same purpose; (2) modifies Requirement R1.2 so that concurrent occurrence of generation deficiency and transmission constraints is not a required condition for CBM usage; (3) modifies Requirement R1.2 to define ''generation deficiency'' based on a specific energy emergency alert level and (4) expands the applicability section to include the entities that actually use CBM, such as LSEs.

1092. In addition, the Commission proposed that NERC should clarify the requirements to address when and how CBM can be used to reduce transmission provider discretion with regard to CBM usage. The Commission provided guidance expressing its belief that CBM should be used only when the LSE's local generation capacity is insufficient to meet balancing Reliability Standards, and that CBM should have a zero value in the calculation of non-firm ATC.

i. Comments

1093. APPA supports the Commission's proposal to approve MOD–006–0. Moreover, APPA agrees with the Commission's proposed directives [345] that the standard should address the use of CBM and TRM for the same purpose. However, APPA believes that the specificity of the Commission's proposed directives to NERC, if implemented, would undermine NERC's role as the approved ERO with the technical expertise to develop and revise standards for the Commission's subsequent review. APPA therefore suggests that the Commission in its Final Rule make clear to NERC its concerns about MOD–006–0, but then let NERC address those concerns through its Reliability Standard development process.

1094. Regarding the Commission's proposal that MOD–006–0 R1.2 be modified ''so that concurrent occurrence of transmission constraints and a generation deficiency is not a requirement for CBM usage,'' WEPCO asserts that the Commission is misinterpreting CBM. WEPCO states that if there is no transmission constraint then there is no need to use CBM. In that case, transmission capacity exists for a LSE to import energy. If there is a transmission constraint, CBM reserves transmission capacity that the LSE can use to import energy for reliability needs.

1095. EEI points out that the explicit intention for CBM is that it be used only during conditions where there are emergency generation deficiencies. However, EEI emphasizes that the Commission's recommendation does not consider that the LSE's supply and demand balance varies season to season, over time, and with supply and demand uncertainties. EEI says that the development of CBM quantities must be carried out in a manner that sets aside transmission capability for forecasted conditions and uncertainties much like the native load reservations necessary for serving reasonably-forecasted native load. An argument may be made that during a period of time when a LSE's expected reserves are substantially greater than its targeted reserves, the need for CBM set-aside decreases. However, should the LSE foresee that this ''excess'' would occur substantially in the future, a reduction in CBM would not be warranted since substantial uncertainties still exist.

1096. Additionally, regarding the Commission's proposal that a LSE that ''has sufficient generation resources within its balancing authority to meet the balancing Reliability Standards, should not need to preserve capacity for CBM at all,'' WEPCO argues that just because the balancing authority has sufficient generation does not mean that there is sufficient transmission capacity to deliver the energy to the LSE. WEPCO states that the LSE may be remote from the bulk of the balancing authority, so there may be occasions when a LSE that has sufficient generation resources within its balancing authority to meet the balancing Reliability Standards may still need to reserve capacity for CBM. In addition, EEI argues that the Commission's viewpoint does not take into account the availability of these resources unless they are under contract with the LSE to provide this service. EEI contends that the implication of this suggestion is to unduly restrict the sources of generation capacity available for CBM during times of generation shortage, which results in the LSE's being captive to local generation that is available and does not allow access to the market outside of the LSE's balancing authority. Additionally, EEI cautions that this action may require the LSE to develop contractual agreements with local generation and thus increase costs to the LSE's rate payers.

1097. Given the strong direction on CBM issues in the OATT Reform NOPR, TAPS assumes that the Commission would not be approving the Version 0 standards on these competitively crucial issues, but would continue to address them forcefully in the OATT Reform proceeding. TAPS notes that, although that is the course largely adopted by the NOPR in this proceeding, the NOPR [346] proposes to approve MOD–006–0 and MOD–007–0, with directions to improve these standards. TAPS notes that such action is inconsistent with the Commission's general approach to ATC/TTC/TRM/CBM standards in this docket and the OATT Reform NOPR. TAPS further states that, given the absence of clear access of non-transmission owner LSEs to CBM, the proposed expansion of MOD–007–0 to include such LSEs in the NOPR [347] seems bizarre.

ii. Commission Determination

1098. The Commission adopts the NOPR proposal to approve MOD–006–0 as mandatory and enforceable. Consistent with Order No. 890 and comments received in response to the NOPR, the Commission directs the ERO to modify MOD–006–0 as discussed below.

1099. Consistent with the views of many commenters, we adopt the NOPR proposal that requires a provision that will ensure that CBM and TRM are not used for the same purpose. As discussed under MOD–004–0 concerning the

[345] NOPR at P 642.

[346] *Id.* at P 642, 648.

[347] *Id.* at P 647–48.

reservation of transfer capacity, we believe that if the Reliability Standard is not clear regarding the conditions specifying both the reservation and the use of CBM, it may cause double-counting. Such double-counting will lead to an unnecessary reduction of ATC, and create opportunities for discrimination. Therefore, we direct the ERO to modify its standard to prevent use of CBM and TRM for the same purposes. We agree with APPA that the ERO should use its Reliability Standards development process to address the double-counting problem.

1100. We adopt the NOPR's proposal and direct the ERO to modify Requirement R1.2 so that a transmission constraint is not a required condition for CBM usage. The glossary definition and the use as defined in Order No. 890 is that CBM ''is intended to be used by the LSE only in time of emergency generation deficiencies.'' [348] Therefore we direct the ERO to modify the standard in the manner proposed in the NOPR.

1101. We adopt the NOPR proposal that requires modification of Requirement R1.2 to define ''generation deficiency'' based on a specific energy emergency alert level. This approach will provide clarity as to when the use of CBM may be permitted. We therefore direct the ERO to modify the Reliability Standard to include a specific energy emergency alert level that will trigger CBM usage.

1102. We also reiterate the direction in Order No. 890 that CBM should have a zero value in the calculation of non-firm ATC because non-firm service may be curtailed so that CBM can be used. CBM is reserved as part of the firm transfer capability so that it is available when needed for energy emergencies. We determine that each LSE should be permitted to call for use of CBM, provided all of the other Requirements of R1.1 are met. We direct that CBM may be implemented up to the reserved value when a LSE is facing firm load curtailments.

1103. We adopt the NOPR proposal that CBM should be used only when the LSE's local generation capacity is insufficient to meet balancing Reliability Standards, with the clarification that the local generation is that generation capacity that is either owned or contracted for by the LSE. We disagree with WEPCO that just because the balancing authority has sufficient generation does not mean that there is transmission capacity to deliver the energy to the LSE. The Commission finds that such a scenario would violate existing transmission operating and transmission planning Reliability Standards. There is an explicit requirement in the transmission operating standards that generation reserves must be deliverable to load.[349] Also, there is an explicit requirement in the transmission planning standards that all firm load must be supplied under various system conditions with and without contingencies.[350] The Commission is not prescribing how these requirements should be met. There are a variety of approaches to do so, including adequate transmission capability, local or dynamic generation transfers into the area or DSM. To clarify for EEI, our proposal does not take into account the availability of these resources unless they are under contract with the LSE to provide this service. We developed our NOPR proposal on the rationale derived from the CBM concept, and believe that if there are enough resources to meet generation reliability criteria within the balancing authority, there is no need to request CBM.

1104. We also adopt the NOPR proposal to require the applicability section to include the entities that actually use CBM, such as LSEs. The current CBM definition in the NERC glossary determines that LSEs are users of CBM. Load-serving entities determine when to use CBM, initiate CBM use and call for its end. Load-serving entities therefore have to comply with the standard requirements that specify the conditions under which CBM will be used. We direct the ERO to modify the standard accordingly.

1105. With regard to TAPS's comments concerning its assumption that the Commission would not be approving the Version 0 standards on these issues, but would continue to address them in the OATT Reform proceeding, the Commission finds that MOD–006–0 and MOD–007–0 do not establish CBM values, but rather address CBM implementation and documentation. The implementation of CBM has critical implications for the reliable operation of the Bulk-Power System and we find that these Reliability Standards should be mandatory and enforceable. The competitively significant issue is to assure that there is no double-counting of CBM and to determine the magnitude of CBM which is addressed in other Reliability Standards that the Commission has not approved or remanded.

1106. The Commission approves MOD–006–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to Reliability Standard MOD–006–0 through the Reliability Standards development process that: (1) Includes a provision that will ensure that CBM and TRM are not used for the same purpose; (2) provides that CBM should be used for emergency generation deficiencies; (3) modifies Requirement R1.2 to define ''generation deficiency'' based on a specific energy emergency alert level; (4) includes a provision that CBM should have a zero value in the calculation of non-firm ATC and (5) expands the applicability section to include the entities that actually use CBM, such as LSEs.

i. Documentation of the Use of Capacity Benefit Margin (MOD–007–0)

1107. MOD–007–0 requires transmission service providers that use CBM to report and post its use.

1108. In the NOPR, the Commission proposed to approve Reliability Standard MOD–007–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–007–0 that expands the applicability section to include the entities that actually use CBM, such as LSEs.

i. Comments

1109. APPA supports the Commission's proposed approval of MOD–007–0. However, it believes that the issue of whether LSEs should be made subject to MOD–007–0 should be left to NERC in the first instance to decide. In so doing, NERC should consider expanding MOD–007–0 to cover not only LSEs, but also balancing authorities. Under NERC's Functional Model, the balancing authority is the entity that would schedule energy over transmission capacity reserved as CBM. Moreover, it is the balancing authority that would know the information necessary to report an incident during which the balancing authority had to import energy from outside the balancing authority's own area from a resource designated as operating reserves and change the net scheduled interchange with the neighboring balancing authorities to allow the energy to flow into the balancing authority's area.

ii. Commission Determination

1110. The Commission approves MOD–007–0 as mandatory and enforceable. Consistent with the comments received in response to the NOPR, the Commission directs the ERO

[348] *See* NERC Glossary at 2.

[349] TOP–002–2.

[350] TPL–002–0.

to modify the standard as discussed below.

1111. We also adopt the NOPR's proposal to require the applicability section to include the entities that actually use CBM and report on their CBM use, such as LSEs. The current CBM definition in the NERC glossary determines when a LSE is a CBM user. The LSE determines how much CBM will be set aside, when CBM use will start and when it will end. The LSE must therefore comply with the standard requirements that require reporting and posting of CBM use. We direct the ERO to modify the standard to include the entities that actually use CBM, such as LSEs. In addition, we agree with APPA that the Reliability Standard should apply to balancing authorities and direct the ERO to include balancing authorities within the entities to which this standard is applicable.

1112. Accordingly, the Commission approves MOD–007–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification through its Reliability Standards development process that expands the applicability of MOD–007–0 to include the entities that actually use CBM, such as LSEs and balancing authorities.

j. Documentation and Content of Each Regional Transmission Reliability Margin Methodology (MOD–008–0)

1113. MOD–008–0 requires the development and posting of a regional methodology for TRM, which is transmission capacity that is reserved to provide reasonable assurance that the interconnected transmission network will remain secure under various system conditions. The Reliability Standard requires each regional reliability organization to: (1) Develop and document a regional TRM methodology in conjunction with its members and (2) post on a Web site the most recent version of its TRM methodology.

1114. In the NOPR, the Commission identified MOD–008–0 as a fill-in-the-blank standard, proposing that because the regional methodologies had not been submitted, the Commission would not propose to approve or remand MOD–008–0 until the ERO submitted the additional information. The Commission expressed concern about the lack of: (1) Clear requirements on how TRM should be calculated and allocated across paths and (2) consistent criteria and clarity with regard to the entity on whose behalf TRM had been set aside.

1115. The Commission requested comment in the NOPR on how TRM is currently calculated and allocated across paths, and what would be a recommended approach for the future.

i. Comments

1116. APPA agrees that MOD–008–0 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations and regional entities develop the necessary regional methodologies and the Commission approves them.

1117. MISO adds that there should be a consistent framework to be followed by entities in determining TRM. It states that relevant MOD standards should be revised if such a framework is not clearly delineated. However, MISO cautions that a Reliability Standard should not be used to address a perceived equity concern. MidAmerican also supports greater uniformity of TRM definitions and calculations, and proposes that a revised standard and/or new standards should encourage transparency with increased availability of information, consistent data input and certain modeling assumptions. International Transmission agrees and proposes that TRM consistency should be addressed either on a regional basis or on an Interconnection-wide basis.

1118. In response to the Commission's request for comments on the current calculation of TRM, and recommended approaches for the future, International Transmission provides a description of the MISO approach to TRM. International Transmission states that during the operating horizon (next 48 hours), TRM is limited to a reserve sharing component which only applies to flowgates that are not based on transmission outages (unit tripping and transmission outages are considered a double contingency). International Transmission states that the logic behind this approach is that there are fewer uncertainties in the operating horizon because schedules and market flows are known. International Transmission explains that during the planning horizon (next 48 hours), a two percent TRM component for uncertainty is used on all flowgates, including those requiring reserve sharing TRM. In addition, other assumptions regarding the sale of transmission service enter into the need for TRM to cover ''uncertainties.'' In addition, International Transmission cautions that MISO's minimal two percent margin may not be sufficient for long-term planning horizon requests (*i.e.*, over 13 months) if planning ''assumptions'' are not reasonable. International Transmission argues that MISO must also employ proper sensitivity studies to other system variables for a two percent margin to be sufficient. TRMs in the five to ten percent range are not necessarily unreasonable if a wide range of potential system operating conditions is not studied. Regardless of the ultimate approach adopted in future standards, International Transmission proposes that all entities follow a consistent framework when calculating TRM.

1119. MidAmerican responds with a discussion of its current approach to TRM calculation, which has been performed in accordance with MAPP-approved methodologies. MidAmerican states that these methodologies include an amount to allow for both the delivery of operating reserves and for uncertainties. Since delivery of operating reserves keeps the interconnected network in service, benefiting all market participants, MidAmerican contends that it is appropriate for TRM to include an amount to allow for the delivery of operating reserves. The allowance for uncertainty is calculated as a percentage of TTC required to protect reliability. All market participants benefit from the provision of an appropriate margin for uncertainty because the reliability of the interconnected network is maintained and service interruptions are reasonably minimized.

1120. With respect to applicable entities, APPA proposes the addition of two new functional entities. Specifically, APPA believes that NERC should expand the applicability section of MOD–008–0 to include planning authorities and reliability coordinators. APPA points out that these are the only entities that can evaluate the amount of error in their transfer capability predictions.

1121. ERCOT states that the Commission's concerns about TRM do not apply to ERCOT, because ERCOT has a balanced grid in which all transmission is firm, no transmission is reserved and there are no transmission paths.

ii. Commission Determination

1122. The Commission does not approve or remand MOD–008–0 until the ERO submits additional information. Consistent with Order No. 890 and comments received in response to the NOPR, the Commission directs the ERO to modify MOD–008–0 through the Reliability Standards development process, as discussed below.

1123. Consistent with the NOPR proposal and Order No. 890, the Commission directs the ERO to modify standard MOD–008–0 to clarify how TRM should be calculated and allocated

across paths or flowgates. We understand that the standards drafting process is underway as a joint project with NAESB. We agree with International Transmission, MidAmerican and MISO about the need for more uniformity and transparency in TRM calculation methodology and use, in order to eliminate potential reliability and discrimination concerns. Consistent with Order No. 890, the Commission directs the ERO to specify the parameters for entities to use in determining uncertainties for which TRM can be set aside and used, such as: (1) Load forecast and load distribution error; (2) variations in facility loadings; (3) uncertainty in transmission system topology; (4) loop flow impact; (5) variations in generation dispatch; (6) automatic reserve sharing and (7) other uncertainties as identified through the NERC Reliability Standards development process. We find that clear specification in this Final Rule of the permitted purposes for which entities may reserve CBM and TRM will also virtually eliminate double-counting of TRM and CBM. Therefore, we direct the ERO to determine clear requirements regarding permitted uses for TRM through its Reliability Standards development process.

1124. We agree with the commenters that the percentage reduction of line rating can be one way to establish an appropriate maximum TRM if thermal considerations are the only limiting factors. While this is a relatively simple method, it ignores limitations relative to voltage or stability limitations which are the more typical reasons for transmission limitations. If adopted as the Reliability Standard method, it should not restrict a transmission provider from using a more sophisticated method that may allow for greater ATC without reducing overall reliability. However, we disagree with the use of an arbitrary percentage over a long time frame that is not based on either proven historical need or sensitivity studies that support that determination. Therefore, consistent with our OATT Reform Final Rule, we direct the ERO to develop requirements regarding transparency of the documentation that supports TRM determination.

1125. We agree with APPA that NERC should revise the applicability section of this standard to add planning authorities and reliability coordinators, and in addition, any other entities that may be identified in the Reliability Standards development process.

1126. Regarding ERCOT's statement that TRM does not apply to ERCOT, we reiterate our position that any request for a regional exemption from the applicable Reliability Standards must take place in the Reliability Standards development process.

1127. The Commission neither accepts nor remands MOD–008–0 until the ERO submits additional information. In the interim, compliance with MOD–008–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission did not propose any action with regard to MOD–008–0, it addressed above a number of concerns regarding the Reliability Standard, consistent with those proposed in Order No. 890. Accordingly, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process including: (1) Clear requirements on how TRM should be calculated, including a methodology for determining the maximum TRM value, and allocated across paths; (2) clear requirements for permitted purposes for which TRM can be set aside and used; (3) clear requirements for availability of documentation that supports TRM determination and (4) expanding the applicability to add planning authorities and reliability coordinators and any other appropriate entity identified in the Reliability Standards development process.

k. Procedure for Verifying Transmission Reliability Margin Values (MOD–009–0)

1128. MOD–009–0 requires each regional reliability organization to develop and implement a procedure to review TRM calculations and the resulting values determined by member transmission providers to ensure compliance with the regional TRM methodology.

1129. In the NOPR, the Commission identified MOD–009–0 as a fill-in-the-blank standard that requires each regional reliability organization to develop a procedure for review of TRM calculations and the resulting values. In the NOPR, the Commission stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD–009–0 until the ERO submits the additional information.

i. Comments

1130. APPA agrees that MOD–009–0 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations and regional entities develop the necessary regional methodologies and the Commission approves them.

ii. Commission Determination

1131. The Commission will not approve or remand MOD–009–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–009–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' Accordingly, the Commission neither approves nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD–009–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

l. Steady-State Data for Modeling and Simulation of Interconnected Transmission System (MOD–010–0)

1132. The purpose of this Reliability Standard is to establish consistent data requirements, reporting procedures and system models for use in reliability analysis. MOD–010–0 requires the transmission owner, transmission planner, generator owner and resource planner to provide steady-state data, such as equipment characteristics, system data, and existing and future interchange schedules to the regional reliability organization, NERC, and other specified entities.

1133. In the NOPR, the Commission proposed to approve Reliability Standard MOD–010–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–010–0 that: (1) Adds a new requirement for transmission owners to provide the list of contingencies they use in performing system operation and planning studies and (2) expands the applicability section to include the planning authority.

i. Comments

1134. APPA agrees with the Commission that MOD–010–0 is sufficient for approval as a mandatory and enforceable Reliability Standard. APPA believes, however, that the Commission's proposed directives to NERC to revise this standard are unduly prescriptive, and may not in fact be the best way to revise the standard.

1135. ISO/RTO Council and ISO–NE do not support adoption of this standard because its requirements refer several

times to the data requirements and reporting procedures specified in MOD–011–0, which has been identified by the Commission as a fill-in the-blank standard. ISO/RTO Council and ISO–NE argue that demonstrating compliance with MOD–010–0 is dependent on an unapproved standard, that the unapproved standard lacks some required criteria or procedures that must be developed by the regional reliability organization, that MOD–010–0 cannot be effectively implemented, and that responsible entities therefore should not be subject to compliance with an incomplete standard.

1136. Constellation strongly supports the Commission's proposals with respect to MOD–010–0 and MOD–012–0 because these proposals, together with other initiatives, such as OATT reform, represent additional steps not only to achieving a reliable bulk power system, but also to reducing undue discrimination in transmission services. Constellation supports the Commission's proposals because they will involve generation owners in facility ratings discussions and discussions of other limiting components and will provide more clarity in the requirements of the Reliability Standard, making enforcement more objective and robust.

1137. Many commenters submitted comments both supporting and opposing the Commission's proposal to modify the standard to require listing the contingencies that transmission owners use when they perform system operation and planning studies.

1138. FirstEnergy supports the Commission's proposal to require transmission owners to provide the list of contingencies used in performing system operation and planning studies. FirstEnergy emphasizes that such a requirement, however, should accommodate various electronic formats that are commonly used in industry simulation tools. FirstEnergy states that compliance with this Reliability Standard should not require transmission owners to replace existing computer and/or software systems, and that the new standard should also require the regional reliability organizations (or Regional Entities) to coordinate the lists of contingencies across wide-areas.

1139. In its support of the Commission's proposal, MidAmerican and TANC stress that a requirement that the transmission owner provide a list of contingencies to neighboring systems will benefit reliability by enabling neighboring systems to accurately study the effects of contingencies on their own systems. In its concurring comments, TANC recommends that the Commission clarify that the list of the contingencies that are used in performing system operation and planning studies include all the contingencies, N–1, N–2, as well as multiple contingencies.

1140. MidAmerican cautions that a list of contingencies could be used in a ''cook-book'' manner to reach the wrong conclusions. A contingency must be modeled in specific and appropriate conditions to understand the reliability issues associated with the contingency.[351] Similarly, NERC states that there may be a need to better understand the reliability need for transmission owners to provide a list of contingencies and to whom the list should be provided.

1141. Northern Indiana and MidAmerican note that such a list of contingencies should be considered a particularly sensitive form of CEII since it would be a list of events that, when they occur, cause critical situations on a system. Northern Indiana and MidAmerican argue that the Commission should include the need to provide for protection against public disclosure through the NERC administrative process in its discussion of any final Reliability Standard. In addition, California Cogeneration states that Requirements R1 and R2 of this standard should not apply to entities that have no material impact on the grid. California Cogeneration warns that the standard may also require generator owners to provide data on behind-the-meter operations, the provision of which should be seriously limited, and data on future interchange schedules, the confidentiality of which should be maintained.

1142. PG&E and Xcel oppose the proposed modification requiring a list of contingencies stating that the requirement is unnecessary and would be unduly burdensome. Xcel also states that the modification would not prove to be useful to neighboring systems. No such lists are currently developed or maintained today. Rather, the contingencies are reflected in the computerized models used by transmission providers for both transmission planning and operations. The models are regularly updated as new facilities are installed. If transmission operators are required to develop such lists, they would be so long and subject to constant change that they would not only be burdensome to develop and maintain, but also unlikely to provide useful information for other transmission owners.

1143. In its opposition to releasing a list of contingencies, PG&E states that performing transmission planning studies is an ambiguous part of the duties of a transmission owner under the NERC Functional Model. Further clarification and refinement of the responsibilities of each entity under the NERC Functional Model may indicate that such studies are among a transmission owner's duties. Until that happens, however, requiring transmission owners to provide contingencies used in performing system operation and planning studies is inappropriate.

1144. SoCal Edison and TVA state that the entity that should be responsible for providing a list of contingencies in performing planning and operation studies is the transmission planner, not the transmission owner. APPA also believes that the transmission operator should be one of the entities required to list contingencies used to perform studies, and that the transmission owner function should be removed as an applicable entity. APPA further notes that the transmission owner does no studies regarding operations or planning. A transmission owner merely owns transmission facilities and maintains those facilities. Moreover, APPA argues that existing studies performed by the transmission planner for the regional reliability organization or planning authority will include a list of contingencies.

1145. Regarding the Commission's proposal to expand the applicability section of this Reliability Standard to include the planning authority, APPA disagrees and recites the comments of MRO, Reliability First and PG&E on the Staff Preliminary Assessment,[352] that to require the planning authority to provide all of this information is duplicative and unnecessary. APPA believes that NERC, as the entity charged with developing standards, is best-suited to address all of these

[351] MidAmerican further cautions that other contingencies exist that must be studied under still-different conditions. Advanced applications associated with real-time contingency analysis review an extensive list of events in combination with other events. Ahead of time, there is no way to be sure exactly which events are the worst in any given operating condition. A single reliability standard cannot contain all the coordination that is needed to allow a system to fully understand all the reliability challenges of a neighboring system. Thus, MidAmerican contends that a better approach is to continue the joint operational and long-term planning that planning authorities, reliability coordinators and other regional entities are currently conducting with transmission planners, transmission owners and others to ensure that the interconnected network is operated and planned in a coordinated way.

[352] NOPR at P 663.

concerns and to develop a consensus standard using its Reliability Standard development process.

1146. TAPS states that this standard would impose unnecessary costs on small systems without improving reliability if applied without the limitation of NERC's bulk electric system definition and NERC's June registry criteria. TAPS opines that modeling will be complicated by the incorporation of low voltage or radial transmission facilities or small generators that have no material impact on bulk transmission system reliability, without improving the results. TAPS further argues that NERC and the Regional Entities—not the Commission—should determine the level of modeling required for reliability.

ii. Commission Determination

1147. The Commission approves MOD–010–0. In addition, the Commission requires the ERO to modify MOD–010–0 as described below.

1148. As an initial matter, the Commission disagrees that MOD–010–0 cannot be implemented until MOD–011–0 is modified. We have directed that data collection and reporting procedures not be interrupted while MOD–011–0 is being modified. Therefore it is possible to implement MOD–010–0. Failure to have the data needed for the steady-state analysis would halt regional reliability assessment processes and hinder planners from accurately predicting future system conditions, which would be detrimental to system reliability. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity the information related to data gathering, data maintenance, reliability assessments and other process-type functions. As we discuss below in the section on MOD–011–0, we direct the ERO to develop a Work Plan that will facilitate ongoing collection of the steady-state modeling and simulation data set forth in MOD–011–0, and submit a compliance filing with that Work Plan.

1149. Supported by many commenters, we adopt the NOPR proposal to direct the ERO to modify MOD–010–0 to require filing of all of the contingencies that are used in performing steady-state system operation and planning studies. We believe that access to such information will enable planners to accurately study the effects of contingencies occurring in neighboring systems on their own systems, which will benefit reliability. Because of the lack of information on contingency outages and the automatic actions that result from these contingencies, planners have not been able to analyze neighboring conditions accurately, thereby potentially jeopardizing reliability on their own and surrounding systems. This requirement will make transmission planning data more transparent, consistent with Order No. 890 requiring greater openness of the transmission planning process.

1150. With respect to TANC's recommendation to modify the standard to require utilities to provide lists of all contingencies they use to operate and plan their systems (N–1, N–2, multiple), we clarify that our requirement specifies contingency files used for all operations and planning. We do not limit the provision of contingency information to single, double or multiple outages. Utilities must provide lists of all the contingencies they use in operations and planning, provided in their original format, regardless of how this data is organized.

1151. In response to MidAmerican, NERC and TANC's concerns that the contingency lists could be used as a ''cook-book,'' our expectation is that utility planners that use these files will have sufficient experience to use them appropriately. We expect that most utility planners are already familiar with their neighbors' system topologies, and have the means, such as bus abbreviation directories and switching diagrams, to identify facilities listed in contingency files.

1152. We agree with FirstEnergy's comments regarding the importance of using existing data collection systems so as to not impose any additional costs on entities. They may file the contingency files in the electronic format in which they were created, along with any necessary decoding instructions. We therefore disagree with PG&E, TAPS and Xcel that this Reliability Standard will be unduly burdensome since it only requires the provision of files that must be developed during the utility's usual planning and operations study process.

1153. Consistent with California Cogeneration, Northern Indiana and MidAmerican's concerns, we determine that those data that a company considers confidential, commercially-sensitive or security-sensitive should be released in accordance with the CEII process or subject to confidentiality agreements. We direct the ERO to address confidentiality issues and modify the Reliability Standard as necessary through its Reliability Standards development process.

1154. We disagree with commenters that generators or small entities that do not have a material impact on grid reliability should be automatically exempt from providing the data required by this Reliability Standard. The Commission believes that all entities that are required to register under the registration process that we have approved must provide data requested by the ERO or the Regional Entity.

1155. We agree with APPA, SoCal Edison and TVA that the functional entity responsible for providing the list of contingencies in performing planning studies should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be one of the entities required to list contingencies used to perform operational studies. Transmission operators are usually responsible for compiling the operational contingency lists for both normal and conservative operation. Therefore, we direct the ERO to modify MOD–010–0 to include transmission operators as an applicable entity.

1156. We adopt our NOPR proposal that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We disagree with APPA that it is duplicative and unnecessary to require the planning authority to provide all of this information. However, we direct the ERO, as the entity charged with developing Reliability Standards, to address all of these concerns and to develop a consensus standard using its Reliability Standard development process.

1157. Accordingly, the Commission approves MOD–010–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD–010–0 through the Reliability Standards development process that: (1) Adds a new requirement in MOD–010–1 for transmission planners to provide the contingency lists they use in performing system operation and planning studies, contained in the electronic format in which they were created, along with any necessary decoding instructions and (2) expands the applicability section to include transmission operators and the planning authority. We also direct the ERO to address confidentiality and small entity issues through the Reliability Standards development process.

m. Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures (MOD–011–0)

1158. The purpose of MOD–011–0 is to establish consistent data requirements, reporting procedures and system models for use in reliability analysis. This Reliability Standard requires the regional reliability organizations to develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each Interconnection.

1159. In the NOPR, the Commission identified MOD–011–0 as a fill-in-the-blank standard that requires each regional reliability organization to develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each Interconnection. The NOPR stated that because the regional methodologies had not been submitted, the Commission would not propose to approve or remand MOD–011–0 until the ERO submits the additional information. In addition, the NOPR suggested that the planning authority plays a significant role in integration of data and thus should be included in the applicability section of MOD–011–0.

i. Comments

1160. APPA agrees with the Commission that this standard is a fill-in-the-blank standard, is not sufficient as currently drafted and should not be approved as a mandatory reliability standard until NERC and the Regional Entities develop the necessary methodologies and the Commission approves them.

1161. TANC supports replacing the term regional reliability organization with an entity from the NERC Functional Model.

ii. Commission Determination

1162. The Commission will not approve or remand MOD–011–0 until the ERO submits additional information. The Commission directs the ERO to modify MOD–011–0 as discussed below.

1163. We reiterate our position stated in the NOPR that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource planning, as well as one of the entities responsible for the integrity and consistency of the data. Therefore, we direct the ERO to add the planning authority to the applicability section of this Reliability Standard.

1164. In response to concerns raised in MOD–010–0 about implementing MOD–010–0 without the data to be collected when MOD–011–0 is modified, we direct the ERO to develop a Work Plan that will facilitate ongoing collection of the steady-state modeling and simulation data specified in MOD–011–0.

1165. Accordingly, the Commission neither accepts nor remands MOD–011–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–011–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' In the interim, compliance with MOD–011–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. We direct the ERO to modify the Reliability Standard through the Reliability Standards development process to expand the applicability section to include the planning authority. Additionally, we direct the ERO to develop a Work Plan and submit a compliance filing that will facilitate ongoing collection of the steady-state modeling and simulation data specified in MOD–011–0.

n. Dynamics Data for Modeling and Simulation of the Interconnected Transmission System (MOD–012–0)

1166. The purpose of MOD–012–0 is to establish consistent data requirements, reporting procedures and system models for use in reliability analysis. MOD–012–0 requires transmission owners, transmission planners, generator owners and resource planners to provide dynamic system modeling and simulation data, such as equipment characteristics and system data, to the regional reliability organization, NERC and other specified entities.

1167. In the NOPR, the Commission proposed to approve Reliability Standard MOD–012–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–012–0 that: (1) Adds a new requirement for transmission owners to provide the list of faults or disturbances they use in performing dynamics system modeling analysis for system operation and planning and (2) expands the applicability section to include the planning authority.

i. Comments

1168. APPA and PG&E agree that the Commission should approve MOD–012–0 as a mandatory and enforceable Reliability Standard. However, PG&E requests the Commission to approve this standard without any modifications. In addition, APPA states that the Commission's proposed directives to NERC to revise this standard are unduly prescriptive, and may not in fact be the best way to revise the standard. APPA notes that NERC, as the technical expert body charged with developing standards, is the entity best suited to hear all of these concerns, and to develop a consensus standard using its Reliability Standards development process.

1169. ISO/RTO Council and ISO–NE disagree with the Commission's proposal to approve this standard, and state that the MOD–012–0 requirements refer several times to the ''data requirements and reporting procedures of MOD–013–0,'' which has been identified by the Commission as a fill-in-the-blank standard, and is pending. Consequently, they argue that MOD–012–0 cannot be effectively implemented, and responsible entities should therefore not be subject to compliance with an incomplete standard.

1170. With respect to the Commission's proposal for adding a new requirement to this standard, FirstEnergy notes that it is appropriate for the Commission to require transmission owners to provide the list of faults or disturbances used in performing dynamics system studies. However, FirstEnergy cautions that such requirement should accommodate various electronic formats that are commonly used in industry simulation tools. FirstEnergy states that compliance with this provision should not require transmission owners to replace existing computer and/or software systems, and that the new standard should also require the regional reliability organizations (or Regional Entities) to coordinate the lists of faults or disturbances across wide-areas.

1171. MidAmerican agrees that requiring transmission owners to provide a list of faults or disturbances to neighboring systems would provide for additional coordination between neighboring utilities, and therefore, would be an improvement to the standard.

However, MidAmerican warns that a list of faults and disturbances could be

used in a ''cook-book'' manner to reach the wrong conclusions.[353]

1172. Northern Indiana and MidAmerican note that such a list of faults and disturbances should be considered a particularly sensitive form of CEII since it would be a list of events that, when they occur, cause critical problems on the system. Northern Indiana and MidAmerican request the Commission to protect sensitive information through the NERC administrative process discussed in the TOP–005–1 Reliability Standard.

1173. Xcel raises the same concern it stated about MOD–010–0 that the proposed modification related to a list of faults and disturbances is unduly burdensome and would not prove useful to neighboring systems. Xcel states that no such lists are currently developed or maintained today, but that the faults and disturbances are reflected in the computerized models used by transmission providers for both transmission planning and operations, which are regularly updated as new facilities are installed. Xcel cautions that the lists, as proposed by the Commission, would be so long and subject to constant change that they would not only be burdensome to develop and maintain, but also unlikely to provide usable information for other transmission owners.

1174. PG&E disagrees with the Commission's proposal related to lists of faults and disturbances, and repeats its comments from MOD–010–0 that this new requirement is unnecessary.

1175. Regarding the functional entities to which this standard applies, APPA notes that the transmission operator and transmission planner, as functions required to provide information regarding stability studies, should be added to the list of applicable entities, while transmission owners should be removed from such list. Under the NERC Functional Model, transmission owners do not perform any studies related to MOD–012–0. Rather, a transmission owner merely owns transmission facilities and maintains them.

1176. California Cogeneration states that this standard raises concerns about data collection and the cost of compliance, and therefore a mechanism for determining no material impact and a provision for exemption is essential for this standard. California Cogeneration also believes that it is unclear what data is included in ''dynamics system modeling and simulation data,'' and whether independent generators would have such data.

ii. Commission Determination

1177. The Commission approves MOD–012–0 as mandatory and enforceable. The Commission directs the ERO to modify MOD–012–0 as discussed below.

1178. As an initial matter, the Commission disagrees that MOD–012–0 cannot be implemented until MOD–013–1 is modified. We have directed that data collection and reporting procedures not be interrupted while MOD–013–1 is being revised, therefore it is possible to implement MOD–012–0. Failure to provide the data needed for dynamics system modeling and simulation would halt regional reliability assessment processes and impede planners from accurately predicting future system conditions, which would be detrimental to system reliability. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entities the information related to data gathering, data maintenance, reliability assessments and other process type functions. As we will discuss in the next section on MOD–013–1, we require the ERO to develop a Work Plan and submit a compliance filing that will facilitate ongoing collection of the dynamics system modeling and simulation data specified by the deferred MOD–013–1 Reliability Standard, which is necessary for implementation of MOD–012–0.

1179. Supported by several commenters, we adopt the NOPR proposal and direct the ERO to modify MOD–012–0 by adding a new requirement to provide a list of the faults and disturbances used in performing dynamics system studies for system operation and planning. We believe that access to such information will enable planners to accurately study the effects of disturbances occurring in neighboring systems on their own systems, which will benefit reliability. This requirement will also make transmission planning data more transparent, consistent with Order No. 890, which calls for greater openness of the transmission planning process on a regional basis.

1180. In response to MidAmerican's concern that fault and disturbance information could be used as a ''cook-book,'' our expectation is that utility planners who use this data have sufficient experience to use it and interpret the results correctly. We expect that most utility planners are already familiar with their neighbors' system topologies, and will be capable of identifying facilities on fault and disturbance lists.

1181. We agree with FirstEnergy's concerns regarding the importance of using existing data collection systems so as to not impose any additional costs on entities. They may file the fault and disturbance information in the electronic format in which they were created, along with any necessary decoding instructions. Compliance with this provision should not require transmission planners to replace existing computer and/or software systems. Therefore, we disagree with PG&E and Xcel that this standard modification will be unduly burdensome.

1182. Consistent with California Cogeneration, Northern Indiana and MidAmerican's concerns, we determine that the data that a company considers confidential, market-sensitive or security-sensitive should be released in accordance with the CEII process or subject to confidentiality agreements. We direct the ERO to address confidentiality issues and modify the standard as necessary through its Reliability Standards development process.

1183. We disagree with commenters that generators or small entities that do not have a material impact on grid reliability should be automatically exempt from providing the data required by this Reliability Standard. The Commission believes that all entities that are required to register under the registration process that we have approved must provide data requested by the ERO or the Regional Entity.

1184. We agree with APPA that the functional entity responsible for providing the fault and disturbance list should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be added to the list of applicable entities in the Reliability Standards development process. Therefore, we direct the ERO to modify

[353] MidAmerican further discusses that the Commission should recognize that caution must be taken in assuming that no other faults and disturbances exist that must be studied under other conditions. MidAmerican states that like with MOD–010–0, ahead of time, there is no way to be sure exactly which faults and disturbances are the worst under given operating conditions. A single reliability standard cannot contain all the coordination needed to allow each system operator to fully understand all the reliability challenges of a neighboring system. Perhaps a better approach is to continue the joint operational and long-term planning that is currently being conducted by planning authorities, reliability coordinators and other regional entities with transmission planners, transmission owners and others to ensure that the interconnected network is operated and planned in a coordinated way.

MOD–012–0 to require the transmission planner to provide fault and disturbance lists.

1185. We adopt our NOPR proposal that planning authorities should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We therefore direct the ERO to add the planning authority to the list of applicable entities.

1186. Accordingly, the Commission approves MOD–012–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD–012–0 through the Reliability Standards development process that: (1) Adds a new requirement for transmission planners to provide the list of faults and disturbances they use in performing dynamic stability analysis in the electronic format in which they were created, along with any necessary decoding instructions and (2) expands the applicability section to include transmission operators, planning authorities and transmission planners. We expect the ERO to address confidentiality issues and modify the Reliability Standard as necessary through the Reliability Standards development process.

o. Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures (MOD–013–1)

1187. MOD–013–1 requires the regional reliability organizations within an Interconnection to develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior and response of each Interconnection. More specifically, the regional reliability organization, in coordination with its transmission owners, transmission planners, generator owners and resource planners within an Interconnection, is required to: (1) Participate in development of documentation for their Interconnection data requirements and reporting procedures; (2) participate in the review of those data requirements and reporting procedures at least every five years and (3) make the data requirements and reporting procedures available to NERC and other specified entities upon request.

1188. In the NOPR, the Commission identified MOD–013–1 as a fill-in-the-blank standard that requires each regional reliability organization within an Interconnection to develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior and response for each of the three NERC Interconnections. The NOPR stated that because the regional methodologies had not been submitted, the Commission would not propose to approve or remand MOD–013–1 until the ERO submits additional information. In addition, in the NOPR we agreed that the Reliability Standard should apply to the planning authority.

1189. In the NOPR, the Commission expressed a concern regarding the 1990 cut-off date,[354] and shared PG&E's concern that the difficulty in obtaining unit-specific data is not limited to the age, but may also be due to other factors such as unit configuration. The Commission requested comment whether it is reasonable to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason. The Commission believes that to achieve the goal of this Reliability Standard of having the ability to accurately model and analyze the dynamic behavior and response of each Interconnection, it is necessary to have accurate data. Inaccurate data can lead to unrealistic simulations and inappropriate actions by responsible entities which may jeopardize the reliability of the Bulk-Power System.

i. Comments

1190. APPA agrees with the Commission that MOD–013–1 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1191. In response to the Commission's request for comments on whether it is reasonable to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason, many commenters responded that it is reasonable to allow estimation of dynamics data for older units where data is not available.[355] The Small Entities Forum expects that the Reliability Standard ultimately will include requirements that such estimates be based on sound engineering principles and be subject to technical review and approval of any estimates at the regional level.

1192. MidAmerican explains that there may be safety or system conditions and/or the loss of records that do not permit gathering unit-specific information, and that in such cases, computations and engineering reports of estimated capability should be sufficient. MidAmerican also requests that if there is a farm of similar generation units (such as wind turbines) or synchronous condensers located in the same general area, providing unit-specific information for a number of identical units is not necessary. Instead, MidAmerican proposes that information about a sample of the identical units (such as two) should be sufficient to provide enough unit-specific information to be representative of the farm. MidAmerican also notes that if units are located in a part of the system that does not typically demonstrate instability, the value of unit-specific data is reduced, and that there are a number of such circumstances in which provision of unit-specific data should not be required.

1193. International Transmission, stating that the age of the unit alone may not be the only reason why unit-specific data might be unavailable, cautions that there should be a requirement in every case that unit data actually be sought for all generating units before estimates of dynamics data are used. International Transmission believes that achieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data, and that, at a minimum, entities should be required to document the steps taken to obtain unit-specific data.

1194. APPA, however, expresses its concern regarding the difficulties in obtaining accurate unit-specific data to model dynamic behavior. APPA recommends to NERC that the regional reliability organizations/Regional Entities and the reliability coordinators review this type of data on a case-by-case basis to test it for accuracy and to determine whether estimated data will produce outputs from the models within acceptable limits. International Transmission confirms that testing is easily accomplished, and provides up-to-date dynamics data reflective of the natural degradation of generating units over their lifetimes. However, International Transmission says that this effort could be tied to the Generator Model Validation Reliability Standards (MOD–024–1 and MOD–025–1).

1195. TANC agrees with the Commission that the standard requirement is arbitrary in imposing the

[354] Requirement R1.1.1 allows for the use of estimated or typical manufacturer's data on pre-1990 units to model dynamic behavior when unit-specific data is unavailable.

[355] EEI, LPPC, MidAmerican, Small Entities Forum and TVA.

1990 cut-off with regard to modeling dynamic behavior. TANC believes that this requirement allows for the use of estimated or typical manufacturer's data on pre-1990 units to model dynamic behavior when unit-specific data is unavailable. TANC notes that difficulty in obtaining unit specific data is not limited to the age of the unit but also unit configuration. TANC therefore recommends that the 1990 cut-off be removed from the proposed Reliability Standard because there is no justifiable basis for the arbitrary cut-off and that the Reliability Standard be revised to allow the generally-accepted use of estimated or typical manufacturer data where unit-specific data is impractical to obtain. TVA agrees that the 1990 cut-off date is unnecessary.

1196. In contrast to those who support rejecting the 1990 cut-off requirement, FirstEnergy states that unit-specific data should be required for all units installed after 1990. EEI confirms that unit-specific information should be available for most units placed in service since 1990.

ii. Commission Determination

1197. The Commission will not approve or remand MOD–013–1 until the ERO submits additional information. The Commission directs the ERO to modify MOD–013–1 through the Reliability Standards development process as discussed below.

1198. We agree with many commenters and direct the ERO to modify the Reliability Standard to permit entities to estimate dynamics data if they are unable to obtain unit-specific data for any reason, not just for units constructed prior to 1990. Achieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data. We disagree with FirstEnergy and EEI and reject the 1990 cut-off date, because the age of the unit alone may not be the only reason why unit-specific data is unavailable. We agree with the Small Entities Forum that the Reliability Standard should include Requirements that such estimates be based on sound engineering principles and be subject to technical review and approval of any estimates at the regional level. That said, the Commission directs that this Reliability Standard be modified to require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.

1199. With respect to small units installed in wind farms, we agree with MidAmerican that data for one unit to represent all identical units at wind farms is acceptable. The Commission understands that this is the current approach with any generator that is manufactured in quantity such as multiple generators used in combined cycle plants.

1200. We adopt our NOPR proposal and direct the ERO to expand the applicability section in this Reliability Standard to include planning authorities because they are the entities responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.

1201. Accordingly, the Commission neither accepts nor remands MOD–013–1 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–013–1 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' In the interim, compliance with MOD–013–1 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission does not approve or remand MOD–013–1, we direct the ERO to modify it through the Reliability Standards development process to: (1) Permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason; (2) require verification of the dynamic models with actual disturbance data and (3) expand the applicability section to include the planning authority, transmission operator and transmission planner. As discussed above in MOD–012–0, we direct the ERO to develop a Work Plan that will facilitate ongoing collection of the dynamics system modeling and simulation data specified in MOD–013–1, and submit a compliance filing containing this Work Plan to the Commission.

p. Development of Steady-State System Models (MOD–014–0)

1202. MOD–014–0 requires the regional reliability organizations within each Interconnection to coordinate and jointly develop and maintain a library of solved Interconnection-specific steady-state models. These models are to include near- and long-term planning horizons representing system conditions for various demand levels. The models are to be updated annually.

1203. In the NOPR, the Commission identified MOD–014–0 as a fill-in-the-blank standard that requires the regional reliability organizations within an Interconnection to develop, coordinate and maintain a library of solved Interconnection-specific steady-state models. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD–014–0 until the ERO submits the additional information. In addition, in the NOPR the Commission stated its belief that the Reliability Standard should be modified to include a requirement to verify that steady-state models are accurate.

1204. In the NOPR, the Commission expressed concern about creating a duplicate effort if both the transmission owner and the regional reliability organization separately develop the steady-state base cases required for the FERC Form 715 filing and for MOD–014–0. The NOPR suggested that the Reliability Standard contain a requirement specifying the time period and planning years be identical to those found in FERC Form 715.[356] Further, the Commission requested comments on any incompatibility between requirements under FERC Form 715 and MOD–014–0.

i. Comments

1205. APPA agrees with the Commission that MOD–014–0, a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1206. NRC suggests that a periodic verification against field data needs to be included in this Reliability Standard.

1207. Regarding the Commission's request for comments on any incompatibility between requirements under FERC Form 715 and MOD–014–0, International Transmission states that the language in MOD–014–0 would allow the regional reliability organization and the transmission owner to develop separate base cases. International Transmission notes that its experience with current practice suggests, however, that this is not a significant concern. Transmission owners now develop the information for inclusion in a regional base case, and the regional base case is rolled up into a FERC Form 715 filing by a regional entity. International Transmission expects that this process would continue in the future.

[356] FERC Form 715 is available at *http://www.ferc.gov/docs-filing/eforms.asp#715*.

1208. MISO believes that FERC should revisit the need for transmission owners to have base case information available for replication. MISO states that the current Interconnection trend is for transmission owners to work together more closely in developing large assessments based on a large model, and that these large assessments are better guides to the overall capability of the transmission grid to move power. MISO believes that these assessments should be filed as part of FERC Form 715.

1209. Although Northern Indiana does not see any duplication or incompatibility with FERC Form 715, Northern Indiana is concerned that the proposed Reliability Standard envisions the use of steady-state models and benchmarking for long-term planning. Northern Indiana believes that benchmarking of planning models should be directed towards validation of line constraints and general comparison of modeled to actual load levels. Northern Indiana suggests that this could be accomplished through validation processes that would first evaluate the data used to model the transformers and the lines and determine that such data is correct, and then compare the loads in total against the actual loads, followed by an examination of individual load points on a system.

ii. Commission Determination

1210. The Commission will not approve or remand MOD–014–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–014–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' The Commission directs the ERO to modify MOD–014–0 as discussed below.

1211. We maintain our position set forth in the NOPR that analysis of the Interconnection system behavior requires the use of accurate steady-state models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We understand that NERC is incorporating recommendations from the Blackout Report [357] and developing models for the Eastern Interconnection.

1212. Further, the maximum discrepancy between the model results and the actual system response should be specified in the Reliability Standard. The Commission believes that the maximum discrepancy between the actual system performance and the model should be small enough that decisions made by planning entities based on output from the model would be consistent with the decisions of operating entities based on actual system response. We direct the ERO to modify MOD–014–0 through the Reliability Standards development process to require that actual system events be simulated and if the model output is not within the accuracy required, the model shall be modified to achieve the necessary accuracy.

1213. We believe that steady-state model validation should not be interrupted while MOD–014–0 is being modified. The lack of accurate models needed for the simulations would halt regional reliability assessment processes and hinder planners from accurately predicting future system conditions, which would be detrimental to system reliability. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide the validated models to regional reliability organizations. We direct the ERO to develop a Work Plan that will facilitate ongoing validation of steady-state models and submit a compliance filing containing the Work Plan with the Commission.

1214. Consistent with many commenters' responses, we find changes to FERC Form 715 are not necessary at this time, because there is no conflict between data gathering and model construction with the FERC Form 715 process.

1215. The Commission neither accepts nor remands MOD–014–0. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–014–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' In the interim, compliance with MOD–014–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. We direct the ERO to: (1) modify the Reliability Standard through the Reliability Standards development process to require actual system events be simulated and model output validated against actual system responses and (2) develop a Work Plan and submit a compliance filing that will enable validation of the steady-state models while MOD–014–0 is being modified.

q. Development of Dynamics System Models (MOD–015–0)

1216. MOD–015–0 requires the regional reliability organizations within each Interconnection to coordinate and jointly develop and maintain a library of initialized (with no faults and disturbances) Interconnection-specific dynamics system models. These models represent near-term years and the years chosen from the longer-term planning horizon.

1217. In the NOPR, the Commission identified MOD–015–0 as a fill-in-the-blank standard that requires the regional reliability organizations within an Interconnection to develop, coordinate and maintain a library of initialized Interconnection-specific dynamics system models. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD–015–0 until the ERO submits the additional information. In addition, the Commission stated that MOD–015–0 should include a requirement to verify accuracy of dynamics system models.

i. Comments

1218. APPA agrees that MOD–015–0 is a fill-in-the-blank standard, is not sufficient as currently drafted and should not be approved as a mandatory reliability standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1219. EEI agrees with the Commission's proposal that a new requirement for verification of the accuracy of dynamics system models should be a part of this Reliability Standard. In addition, EEI states that the validation of models is a valid concern, but that any requirement in this area should be carefully considered, and that any requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing procedures to verify the models. EEI believes that it would not be reasonable to subject generation units to artificial disturbances to validate the models. NRC recommends periodic verification against field data. APPA notes that if NERC modifies MOD–015–0 as APPA anticipates, a requirement to verify the accuracy of the dynamics system model would be included and the Regional Entity would be the compliance monitor.

[357] Recommendation Number 24 of the Blackout Report at 160.

ii. Commission Determination

1220. The Commission will not approve or remand MOD–015–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–015–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' The Commission directs the ERO to modify MOD–015–0 through the Reliability Standards development process as discussed below.

1221. We maintain our position set forth in the NOPR that the analysis of Interconnection system behavior requires the use of accurate dynamics system models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We agree with EEI and NRC and confirm our position that a requirement to verify that dynamics system models are accurate should be a part of this Reliability Standard. We agree with EEI that this new requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing procedures to verify the models. We direct the ERO to modify the standard to require actual system events be simulated and dynamics system model output be validated against actual system responses.

1222. We believe that dynamics system model validation should not be interrupted while MOD–015–0 is in the modification process. The lack of accurate models needed for the simulations would halt regional reliability assessment processes and hinder planners from accurately predicting future system conditions, which would be detrimental to system reliability. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity the validated dynamics system models while MOD–015–0 is being modified. We require the ERO to develop a Work Plan that will enable continual validation of dynamics system models and submit a compliance filing with the Commission.

1223. The Commission neither accepts nor remands MOD–015–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–015–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' In the interim, compliance with MOD–015–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. We direct the ERO to: (1) Modify the Reliability Standard through the Reliability Standards development process to require verification of the accuracy of dynamics system models and (2) develop a Work Plan and submit a compliance filing that will facilitate ongoing verification of the accuracy of dynamics system models while MOD–015–0 is being modified.

r. Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load and Controllable Demand-Side Management (MOD–016–1)

1224. The purpose of MOD–016–1 is to ensure that past and forecasted demand data is available for validation of past events and future system assessments. MOD–016–1 requires the planning authority and the regional reliability organization to have documentation identifying the scope and details of the actual and forecast demand and load data, and controllable DSM data to be reported for system modeling and reliability analysis.

1225. In the NOPR, the Commission proposed to approve Reliability Standard MOD–016–1 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–016–1 that expands the applicability section to include the transmission planner.

i. Comments

1226. APPA agrees that MOD–016–1 is sufficient for approval as a mandatory and enforceable reliability standard.

1227. In contrast, ISO/RTO Council and ISO–NE do not support adoption of this standard because it is contingent on standards that are pending approval by the Commission based on their characterization as applying only to regional reliability organizations, or because they have been categorized as fill-in-the-blank standards.[358] ISO/RTO Council and ISO–NE agree that as a result, MOD–016–1 cannot be effectively implemented.

1228. APPA and FirstEnergy agree with the Commission's proposal to direct NERC to add the transmission planner function to the applicability section of the standard, although they argue that NERC, as the standards-setting entity, should make the decision.

1229. TAPS does not oppose the proposed applicability of MOD–016–1, but opposes regional interpretations that apply the standard more broadly. TAPS criticizes SERC's supplement to MOD–016–1 that makes the standard applicable to LSEs, even though LSEs do not have the ability to identify the scope and details of the data required to be reported for system modeling and reliability analyses. TAPS contends that there are no physical differences that make SERC LSEs more capable in this regard than LSEs in other regions. TAPS recommends that the Commission clarify that it expects standards to be applied in a consistent and uniform manner as written, and will look closely at regional variations not justified by physical differences.

1230. In contrast to APPA, FirstEnergy and TAPS, EEI believes that the standard assigns appropriate responsibility, and that the transmission planner should not be added to the applicability section of this standard. According to EEI, the transmission planner has no specific responsibilities for ensuring data integrity in day-to-day practice. EEI understands that data integrity falls within the daily responsibilities of data management functions, such as metering. EEI states that the NERC Functional Model does not describe technical functions at this level of detail. EEI notes, as it also notes in its comments on the TPL standards, that load-related DSM data of the type and specificity stated in the NOPR, such as load control of customer-owned appliances, is related to distribution system and operations planning, and not to transmission system planning.

ii. Commission Determination

1231. The Commission approves MOD–016–1 as mandatory and enforceable. In addition, the Commission directs the ERO to modify MOD–016–1 as discussed below.

1232. As an initial matter, we disagree that MOD–016–1 cannot be implemented until other unapproved standards are modified. As previously stated, we are requiring the ERO to provide a Work Plan and compliance filing regarding collection of information specified under standards that are deferred, and believe there should be no difficulties complying with this Reliability Standard. We reiterate that continual collection of data is necessary to maintain system reliability, and approval of MOD–016–1 will help to achieve this objective.

1233. Supported by many commenters, the Commission directs

[358] TPL–005–0, TPL–006–0, MOD–011–0, MOD–013–0, MOD–014–0 and MOD–015–0.

the ERO to modify MOD–016–1 and expand the applicability section to include the transmission planner, on the basis that under the NERC Functional Model the transmission planner is responsible for collecting system modeling data, including actual and forecast load, to evaluate transmission expansion plans. We disagree with EEI that this Reliability Standard should not be applied to the transmission planner because load-related data for controllable DSM is not only needed for distribution and transmission operations, but is also necessary for the transmission planner to take controllable DSM into account in planning the transmission system. Requirement R1.1 relates to data submittal, and requires data to be consistent with that supplied for the TPL–005 and TPL–006 standards, which clearly apply to transmission planners. We approve the ERO's definition in the glossary of DSM as ''all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use.'' Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. Specifically, we direct the ERO to add to its definition of DSM ''any other entities'' that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.

1234. In response to TAPS's criticism of SERC's desire to expand its regional standards relative to actual and forecast load to include LSEs, we clarify that we can only act on the standards before us. We do not make a decision on SERC's standards in this rule. We therefore recommend that TAPS raise this issue in the Reliability Standards development process.

1235. The Commission approves Reliability Standard MOD–016–1 as mandatory and enforceable and directs the ERO to develop a modification to MOD–016–0 through the Reliability Standards development process to include the transmission planner in the applicability section.

s. Aggregated Actual and Forecast Demands and Net Energy for Load (MOD–017–0)

1236. The purpose of MOD–017–0 is to ensure that past and forecasted demand data is available for past event validation and future system assessment. MOD–017–0 requires LSEs, planning authorities and resource planners to annually provide aggregated information on: (1) Integrated hourly demands; (2) actual monthly and annual peak demand (MW) and net load energy (GWh) for the prior year; (3) monthly peak demand forecasts and net load energy for the next two years and (4) annual peak demand forecasts (summer and winter) and annual net load energy for at least five and up to ten years into the future.

1237. In the NOPR, the Commission proposed to approve Reliability Standard MOD–017–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–017–0 that includes new requirements for: (1) Reporting of temperature and humidity along with peak loads and (2) reporting of the accuracy, error and bias of load forecasts compared to actual loads while taking temperature and humidity variations into account.

i. Comments

1238. APPA agrees that the Commission should approve MOD–017–0 as mandatory and enforceable.

1239. In contrast to APPA, ISO–NE does not support approval of this standard because MOD–017–0 depends on MOD–016–0, which further depends on various unapproved standards. ISO–NE believes that this makes MOD–017–0 dependent on unapproved standards, and that consequently, MOD–017–0 cannot be effectively implemented. Similarly, ISO/RTO Council states that if the Commission does not approve MOD–016–0, then MOD–017–0 will refer to an unapproved standard.

1240. Although MidAmerican does not oppose the Commission's proposal regarding reporting of temperature and humidity along with peak loads, it finds it of only limited value. MidAmerican notes that there are typically other explanatory variables, such as economic variables, that are needed to understand the relationship between system load and temperature and humidity. In addition, the relationship and the importance of temperatures are different for every utility, which limits the effectiveness of standardization. FirstEnergy suggests that NERC should allow for a transition period for entities that currently do not track temperature and humidity along with peak load.

1241. Xcel states that in many areas of the country, humidity is not a weather-indicator for peak load. Xcel therefore suggests that instead of including a reporting requirement for humidity, the standard be revised to include a more generic term, such as ''peak producing weather conditions.'' Alcoa requests that the Commission clarify that these requirements would only apply to load that varies with temperature and humidity.[359]

1242. Regarding the Commission's proposal for reporting of the accuracy, error and bias of load forecasts compared to actual loads while taking temperature and humidity variations into account, APPA disagrees that the Commission should direct NERC to modify MOD–017–0 to include these requirements. APPA argues that requiring the type and granularity of forecast information and data the Commission proposes would not necessarily increase the reliability of load forecasts. APPA believes that it should be up to NERC, as the expert standards-setting entity, to decide whether such information would yield enough useful data to make it worth mandating.

1243. TAPS is concerned that the NOPR's recommendation for reporting the accuracy, error and bias of load forecasts compared to actual loads may be interpreted to mean that measuring compliance is a function of forecast accuracy. TAPS contends that reliance on percentage-based deviations as a measurement of compliance is inappropriate when applied to very small entities because an error that in absolute terms is too small to affect the Bulk-Power System might be a significant percentage of the entity's load.

1244. EEI notes that the direction of the NOPR proposal seems to suggest an expansion of the current reporting processes required under the Energy Information Administration section 411 process. EEI suggests that such a proposal should consider whether the section 411 process itself requires change or provides for an adequate level of reporting, and the extent to which an explicit NERC process requirement could distract or confuse industry participants.

1245. FirstEnergy states that the transmission planner should be added to the list of applicable entities for this standard. FirstEnergy also states that it may be reasonable to interpret or apply this Reliability Standard in a manner to permit an affected entity that is a subsidiary in a utility holding company corporate structure to satisfy its

[359] Alcoa states that because its smelting load (the vast majority of its load) does not vary in accordance with temperature and humidity, comparing Alcoa's load forecasts to actual loads taking this information into account would be burdensome without being useful.

reporting requirements by means of a corporate affiliate. Adopting this interpretation or application would promote efficiency and decrease confusion in circumstances where several utility subsidiaries in the same corporate family are subject to this Reliability Standard.

1246. MISO recommends that the Commission direct NERC to change the requirement of this standard so that aggregated actual hourly demand data (at the balancing authority level) are to be provided within 30 calendar days of a request from NERC. MISO believes that load aggregated at this level should be sufficient for the modeling activities associated with system reliability. MISO understands that hourly data is collected by those utilities that have balancing authority responsibilities, and that these utilities can report aggregated hourly loads for their responsibility area within 30 days. MISO notes that some balancing authority utilities provide energy services to smaller municipal or distribution cooperative utilities where the metering system records only the peak demand and total energy supplied over approximately 30 days. MISO cautions that the balancing authority will usually have hourly data for demand and energy within a segment of the network, but may have no hourly metering on a specific customer served by that segment.

ii. Commission Determination

1247. The Commission approves MOD–017–0 as mandatory and enforceable. In addition, the Commission directs the ERO to modify MOD–017–0 as discussed below.

1248. As an initial matter, we disagree that MOD–017–0 cannot be implemented because it is dependent on MOD–016–0, which further depends on various unapproved standards. As previously stated, we direct the ERO to provide a Work Plan and compliance filing regarding the collection of information specified under standards that are deferred, and believe there should be no difficulty complying with this Reliability Standard. We reiterate that ongoing collection of data is necessary to maintain system reliability, and approval of MOD–017–0 will help achieve this goal.

1249. As a general matter, the Commission is required to insure that the Reliability Standards are sufficient to adequately protect Bulk-Power System reliability.[360] One of the main drivers in achieving Reliable Operation is to accurately predict the firm transactions and native load that must be served. Understanding the accuracy, error and bias of the forecast and taking action to minimize them would improve the Reliability Standards and achieve the goal.

1250. The Commission also directs the ERO to modify the Reliability Standad to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values.[361] In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term ''peak producing weather conditions'' because it is too generic for a mandatory Reliability Standard.

1251. We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.

1252. The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.

1253. The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.

1254. Regarding TAPS's concern that accuracy of reporting may be used as a compliance Measure, we clarify that the compliance Measures for this Reliability Standard do not measure accuracy as a compliance Measure. Any change in the Measures would be arrived at in the Reliability Standards development process.

1255. The Commission acknowledges EEI's concern that a requirement for additional information may impose an expansion of existing Energy Information Administration section 411 reporting requirements.[362] We believe, however, that the ERO can ensure that the additional reporting of temperature and humidity along with peak loads does not conflict with or jeopardize the Energy Information Administration section 411 reporting process.

1256. We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.

1257. The Commission disagrees in general with MISO's recommendation to allow some exceptions to the requirement to provide hourly demand data. However, the metering for some customer classes may not be designed to provide certain types of data. The Commission therefore directs the ERO to consider MISO's concerns in the Reliability Standards development process.

1258. The Commission approves Reliability Standard MOD–017–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD–017–0 through the Reliability Standards development process that includes requirements for: (1) Reporting of temperature and humidity along with the peak loads; (2) reporting of accuracy,

[360] Order No. 672 at P 329.

[361] *See* Brattle Group Report on PJM Load Forecast Model, available at *http://www.pjm.com/planning/res-adequacy/load-forecast.html.*

[362] Form EIA–411, ''Coordinated Bulk Power Supply Program Report'' collects information about regional electric supply and demand projections for a five-year advance period as well as information on the transmission system and supporting facilities. *See http://www.eia.doe.gov/cneaf/electricity/page/forms.html.*

error and bias of load forecasts compared to actual loads taking temperature and humidity variations into account; (3) addressing methods to correct forecasts to minimize prior inaccuracies, errors and bias and (4) including the transmission planner in the applicability section.

t. Treatment of Nonmember Demand Data and Uncertainties in the Forecasts of Demand and Energy for Load (MOD–018–0)

1259. The purpose of MOD–018–0 is to ensure that past and forecasted demand data are available for past event validation and future system assessment. MOD–018–0 requires LSEs, planning authorities, transmission planners and resource planners to submit load data reports that: (1) Indicate whether the demand data includes the regional reliability organization's non-members' demands and (2) addresses how assumptions, methods and uncertainties are treated.

1260. In the NOPR, the Commission proposed to approve MOD–018–0 as mandatory and enforceable.

i. Comments

1261. APPA agrees that MOD–018–0 is sufficient for approval as a mandatory and enforceable reliability standard.

1262. In contrast to APPA, ISO/RTO Council and ISO–NE view MOD–018–0 as dependent upon fill-in-the-blank NERC standards, and as such, argue that the Commission should refrain from approving the Reliability Standard at this time. ISO–NE states that approval of this standard would create dependency of MOD–018–0 on other unapproved standards. Consequently, ISO–NE contends that MOD–018–0 cannot be effectively implemented.

1263. TAPS reiterates a similar concern it expressed with regard to MOD–017–0. TAPS notes that uncertainty in a small entity's forecast is insignificant. TAPS recommends that load forecast uncertainty should be addressed at an aggregate level on a regional basis (as is often done in the establishment of reserve obligations).

ii. Commission Determination

1264. The Commission approves MOD–018–0 as mandatory and enforceable.

1265. As an initial matter, we disagree that MOD–018–0 cannot be implemented because it is dependent on various unapproved standards. As previously stated, we direct the ERO to provide a Work Plan and compliance filing regarding the collection of information specified for standards that are deferred, and believe there should be no difficulties complying with this Reliability Standard. We reiterate that ongoing collection of data is necessary to maintain system reliability, and approval of MOD–018–0 will help to achieve this goal.

1266. Regarding TAPS's concern that small entities should not be required to comply with MOD–018–0 because their forecasts are not significant for system reliability purposes, the Commission directs the ERO to address this matter in the Reliability Standards development process.

u. Reporting of Interruptible Demands and Direct Control Load Management (MOD–019–0)

1267. The purpose of MOD–019–0 is to ensure that past and forecasted demand data is available for past event validation and future system assessment. The Reliability Standard requires that LSEs, planning authorities, transmission planners and resource planners annually provide their forecasts of interruptible demands and direct control load management to NERC, the regional reliability organization and other entities as specified in MOD–016–1, Requirement R1. The data should contain the forecasts for at least five years, and up to ten years.

1268. In the NOPR, the Commission proposed to approve Reliability Standard MOD–019–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–019–0 that includes new requirements for reporting of the accuracy, error and bias of controllable load [363] forecasts.

i. Comments

1269. APPA agrees that MOD–019–0 should be approved as mandatory and enforceable. However, APPA states that the proper entity to decide whether the recommended changes to the standards should be made is NERC, through Reliability Standards development process.

1270. The ISO/RTO Council and ISO–NE note that MOD–019–0 is dependent, through MOD–016, on various unapproved standards. Consequently, they contend that MOD–019–0 cannot be effectively implemented.

1271. APPA proposes that NERC consider modifying MOD–019–0 to include new requirements for reporting on the accuracy, error and bias of controllable load forecasts. APPA further believes that NERC should consider adding requirements that would require resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load required in MOD–019–0 and identify what corrective actions were taken to improve controllable load forecasting for the 10-year planning horizon.

1272. EEI and FirstEnergy state that determining the precise availability and capability of direct load control is a difficult management and customer relations exercise, and therefore, this requirement should not be included in the Reliability Standard. EEI states that, unlike other technical requirements for generation resources to be tested for various capabilities and limits under different types of stresses, there are no similar requirements for load control equipment. Elsewhere in these comments, EEI supports explicit recognition that load control should be recognized on the same terms as generation resources for setting reserve requirements. However, EEI cautions against imposing requirements to verify load control devices and interruptible loads, because the practical complexities of conducting such testing and verification, including customer notification, the need to plan, manage, and coordinate testing with critical commercial and industrial customer activities, and the need to conduct such tests at times of peak load, make this an extremely difficult operational challenge.

1273. International Transmission notes that many load control applications are not individually metered, which means impact can only be estimated within a LSE's service territory. International Transmission believes that accurate reporting may not be feasible.

1274. TAPS raises concern that the Commission's recommendation in the NOPR may be interpreted to make forecast accuracy a component of Reliability Standards compliance. TAPS cautions that reliance on percentage-based deviations as a measurement of compliance is inappropriate when applied to very small entities because an error that in absolute terms is too small to affect the Bulk-Power System might be a significant percentage of the entity's load. The percentage deviation from a forecasted peak of a small (*e.g.*, 10 MW) entity will almost always be significantly higher than the percentage deviation of a large (more than 10,000 MW) entity, but the smaller system's deviation will have little if any impact on the bulk transmission system. In other contexts, the Commission has recognized that reliance solely on

[363] While MOD–019–0 and MOD–020–0 use two separate terms, interruptible load and direct control load management, the NOPR uses ''controllable load'' to refer to both of them.

percentage deviations as compliance measures can produce discriminatory results, and has applied MW minimums to minimize the discrimination that would otherwise result.

ii. Commission Determination

1275. The Commission approves MOD–019–0 as mandatory and enforceable. In addition, the Commission directs the ERO to modify MOD–019–0 as discussed below.

1276. As an initial matter, we disagree that MOD–019–0 cannot be implemented because it is dependent on MOD–016–0, which further depends on various unapproved standards. As previously stated, we direct the ERO to provide a Work Plan and compliance filing regarding the collection of information specified under related standards that are deferred, and believe there should be no difficulties complying with this Reliability Standard. We reiterate that ongoing collection of data is necessary to maintain system reliability, and approval of MOD–019–0 will help to achieve this goal. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity information related to forecasts of interruptible demands and direct control load management.

1277. The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern. We also note that EEI is concerned about such testing at times of peak load. We clarify that we are not requiring the testing to be conducted at peak load conditions. Consequently, we reject the proposals of EEI, FirstEnergy and International Transmission to discard the requirement for reporting of the accuracy, error and bias of controllable load forecasts.

1278. We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD–019–0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.

1279. Regarding TAPS' concern that reporting accuracy could be used as a compliance Measure, we clarify that compliance Measures for this Reliability Standard do not include accuracy as a compliance measure. Any change in this policy would be arrived at in the ERO Reliability Standards development process.

1280. Accordingly, the Commission approves MOD–019–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD–019–0 through the Reliability Standards development process to require: (1) Reporting of the accuracy, error and bias of controllable load forecasts and (2) analyzing differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.

v. Providing Interruptible Demand and Direct Control Load Management Data to System Operators and Reliability Coordinators (MOD–020–0)

1281. The purpose of MOD–020–0 is to ensure that past and forecasted demand data are available for validation of past events and future system assessment. The Reliability Standard requires that each LSE, planning authority, transmission planner and resource planner identify its amount of: (1) Interruptible demand and (2) direct control load management to transmission operators, balancing authorities and reliability coordinators upon request.

1282. In the NOPR, the Commission proposed to approve Reliability Standard MOD–020–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–020–0 that includes a new requirement concerning the reporting of the accuracy, error and bias of controllable load forecasts in its Reliability Standards development process.

i. Comments

1283. APPA supports approval of MOD–020–0 as mandatory and enforceable, as proposed by the Commission. APPA does not oppose NERC's consideration of possible changes to MOD–020–0 regarding the reporting of the accuracy, error and bias of controllable load forecasts.

1284. EEI and FirstEnergy state that for practical reasons, determining the precise availability and capability of direct load control is a difficult management and customer relations exercise. Unlike other technical requirements for generation resources to be tested for various capabilities and limits under different types of stresses, there are no similar requirements for load control equipment. The practical complexities of conducting such testing and verification, including customer notification, the need to plan, manage and coordinate testing with critical commercial and industrial customer activities, and the need to conduct such tests at times of peak load make this an extremely difficult operational challenge.

1285. LPPC opposes the Commission's proposal for modification to report the accuracy of load forecasts. LPPC points out that load reduction forecasts are imprecise by nature, and, consequently, some utilities do not undertake them. LPPC also notes that interruptible loads are often on one-year contracts and, in some regions, instances of entities actually exercising load reduction are rare; in these areas, system operators often do not separately forecast interruptible load reductions, and reporting on the accuracy of forecasts on interruptible load reductions, even if interruptible load forecasts were done, is of little value. LPPC states that in other areas, such as New York, interruptible load reductions are more predictable, because many large loads have signed interruptible load contracts and have a history of exercising load reductions. LPPC notes that system operators in areas similar to New York have sufficient data so that forecasting for interruptible loads is a useful exercise, and as a result, a requirement to report on the accuracy of forecasts in these regions would be of some value, but not elsewhere. Consequently, LPPC recommends that the requirement should be region-specific and should only apply to entities that separately forecast interruptible loads. LPPC further notes that energy efficiency programs are often built into the larger assumptions in the forecast and are not separately forecasted.

1286. TAPS is concerned that the Commission's recommendation in the NOPR may be interpreted to make forecast accuracy a component of Reliability Standards compliance.

However, it asserts that reliance on percentage-based deviations as a measurement of compliance is inappropriate when applied to very small entities because an error that in absolute terms is too small to affect the Bulk-Power System might be a significant percentage of the entity's load. The percentage deviation from a forecasted peak of a small (*e.g.*, 10 MW) entity will almost always be significantly higher than the percentage deviation of a large (more than 10,000 MW) entity, but the smaller system's deviation will have little if any impact on the bulk transmission system. In other contexts, the Commission has recognized that reliance solely on percentage deviations as a compliance measure can produce discriminatory results, and has applied MW minimums to minimize the discrimination that would otherwise result.

ii. Commission Determination

1287. The Commission approves MOD–020–0 as mandatory and enforceable. In addition, the Commission directs the ERO to modify MOD–020–0 as discussed below.

1288. We adopt the proposal to direct the addition of a requirement for reporting of the accuracy, error and bias of controllable load forecasts because we believe that reporting of this information will provide applicable entities with advanced knowledge about the exact amount of available controllable load, which will improve the accuracy of system reliability assessments. The Commission finds that controllable load in some cases may be as reliable as other resources and therefore must also be subject to the same reporting requirements. We recognize that determining the precise availability and capability of direct load control is a difficult management and customer relations exercise, but we do not believe that it will be overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern. Regarding LPPC's suggestion that this requirement should be region-specific and should only apply to entities that separately forecast interruptible loads, we note that if a region does not forecast interruptible loads, this Reliability Standard does not apply.

1289. Regarding TAPS' concern that forecast accuracy may be interpreted as a component of Reliability Standards compliance, we clarify that compliance Measures for this Reliability Standard do not measure accuracy as a compliance measure. Any change in this policy would be arrived at in the ERO Reliability Standards development process.

1290. The Commission approves Reliability Standard MOD–020–0 as mandatory and enforceable and directs the ERO to develop a modification to MOD–020–0 through the Reliability Standards development process to require reporting of the accuracy, error and bias of controllable load forecasts.

w. Documentation of the Accounting Methodology for the Effects of Controllable Demand-Side Management in Demand and Energy Forecasts (MOD–021–0)

1291. MOD–021–0 requires LSEs, transmission planners and resource planners to clearly document how each addresses the demand and energy effects of DSM programs. The standard also requires an applicable entity to include information detailing how DSM measures are addressed in the forecasts of its peak demand and annual net energy for load in the data reporting procedures of MOD–016–0, Requirement R1.

1292. In the NOPR, the Commission proposed to approve Reliability Standard MOD–021–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–021–0 that: (1) Includes a requirement standardizing principles on reporting and validation of DSM program information and (2) modifies the title and purpose statement to remove the word ''controllable.''

i. Comments

1293. APPA supports the Commission's approval of MOD–021–0 as mandatory and enforceable.

1294. In contrast, ISO–NE and ISO/RTO Council oppose adoption of this standard by the Commission. ISO–NE argues that the LSE, transmission planner and resource planner should each include information regarding how DSM measures are addressed in the forecasts of its peak demand and annual net energy for load in the data reporting procedures of MOD–016–0 R1. Therefore, they contend that, because MOD–016–0 is dependent on various unapproved Reliability Standards, MOD–021–0 is also dependent on unapproved Reliability Standards. Consequently, ISO–NE contends that MOD–021–0 cannot be effectively implemented.

1295. FirstEnergy and SMA support the Commission's proposal to require consistent and uniform methods for reporting and validating demand-side information. SMA notes that this will provide more consistent and uniform evaluation of demand response data to facilitate system operator confidence in relying on such resources for various reliability purposes. In addition, APPA believes that NERC should consider adding requirements to MOD–021–0 that would provide information to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. APPA believes that all of these proposals should be submitted to NERC as the standards-setting body with technical expertise, and vetted through its Reliability Standards development process, rather than being imposed by Commission fiat.

1296. FirstEnergy adds that MOD–019–0, MOD–020–0 and MOD–021–0 should be combined because they all address load forecast inputs, and that combining these standards will eliminate any inconsistencies and make compliance easier and more efficient.

ii. Commission Determination

1297. The Commission approves MOD–021–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD–021–0 through the Reliability Standards development process as discussed below.

1298. As an initial matter, we disagree that MOD–021–0 cannot be implemented because it is based on MOD–016–0, and through it on various unapproved standards, which creates an implementation problem. As previously stated, we direct the ERO to provide a Work Plan and compliance filing regarding collection of information specified under related standards that are deferred, and believe there should be no difficulty complying with this Reliability Standard. We reiterate that ongoing collection of data is necessary to maintain system reliability, and approval of MOD–21–0 will help to achieve this goal. Therefore, we direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity the information required by this Reliability Standard.

1299. We agree with FirstEnergy and SMA that standardization of principles on reporting and validating DSM program information will provide consistent and uniform evaluation of demand response to facilitate system operator confidence in relying on such resources, which will further increase accuracy of transmission system reliability assessment and consequently

enhance overall reliability. We direct the ERO to modify this Reliability Standard to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. Therefore, we adopt the NOPR proposal and direct the ERO to modify MOD–021–0 by adding a requirement for standardization of principles on reporting and validating DSM program information.

1300. With respect to FirstEnergy's suggestion to combine MOD–019–0, MOD–020–0 and MOD–021–0, we understand that the ERO intends to consolidate Reliability Standards and encourage FirstEnergy to make its suggestion in the Reliability Standards development process.

1301. The Commission directs the ERO to modify the title and purpose statement to remove the word ''controllable.'' We note that no commenter disagrees.

1302. The Commission approves Reliability Standard MOD–021–0 as mandatory and enforceable. We direct the ERO to develop a modification to MOD–021–0 through the Reliability Standards development process to (1) add a Requirement standardizing principles on reporting and validation of DSM program information; (2) allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts and (3) modify the title and purpose statement to remove the word ''controllable.''

x. Verification of Generator Gross and Net Real Power Capability (MOD–024–1)

1303. The purpose of MOD–024–1 is to ensure that accurate information on generation gross and net real power capability is used for reliability assessments. The Reliability Standard requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net real power capability. It also requires a generator owner to follow its regional reliability organization's procedure for verifying and reporting gross and net real power generating capability.

1304. In the NOPR, the Commission identified MOD–024–1 as a fill-in-the-blank standard that requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net real power capability. The Commission stated that because the regional procedures had not been submitted, it would not propose to approve or remand MOD–024–1 until the ERO submits the additional information. In addition, the Commission expressed concern that the Reliability Standard is not sufficiently clear because it does not define test conditions, *e.g.*, ambient temperature, river water temperature or methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. Further, the NOPR stated that Requirement R2 provides that the ''regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval'' and noted that it is not clear what approval is required and when the 30-day period starts.

i. Comments

1305. APPA agrees that MOD–024–1 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1306. APPA also states that the results of field-testing will enable NERC to refine this Reliability Standard in an appropriate manner. APPA further believes that NERC should consider modifying this Reliability Standard to provide requirements for this information on an Interconnection-wide basis, in the same manner that IRO–006–2 sets the requirement for transmission loading relief in each Interconnection.

1307. Northern Indiana urges the Commission to reconsider the proposed changes at this time in favor of continuation of the currently-effective Reliability Standard. Northern Indiana states that the NOPR's suggestion that there should be greater specificity and definition of test conditions could potentially create reliability issues, rather than protect against them. Northern Indiana explains that certain types of testing, and their preparation, can be accomplished more quickly than others, with test duration varying from several minutes to several days.[364] The problem is compounded if a test takes some time to complete, and all neighboring generating owners were required to comply at the same time. The end result would be a lack of regulating capability in a region.

1308. Constellation encourages the Commission and NERC to take extra care in distinguishing between those requirements in each Reliability Standard that are core requirements as opposed to supporting information, explanatory statements or administrative processes. For example, Constellation points out that in MOD–024–1, NERC proposes that a verification process be made into a Reliability Standard with full enforceability. Although Constellation agrees that the verification process spelled out in this Reliability Standard is important and should be performed by the industry, the Reliability Standard, alone, exclusively provides for an administrative process and, therefore, if not strictly complied with, does not necessarily foreshadow an immediate, real-time reliability problem on the bulk electric system. Constellation is concerned that the Levels of Non-Compliance associated with MOD–024–1 and MOD–025–1 are based on arbitrary percentages that have little to do with the impact a failure to perform would have on reliability. Constellation believes that these problems ultimately will reduce the effectiveness of the Reliability Standards. Consequently, Constellation requests that the Commission recognize these concerns and direct NERC to take them into consideration during the Reliability Standards development process.

ii. Commission Determination

1309. The Commission will not approve or remand MOD–024–1 until the ERO submits additional information. In order to continue verifying and reporting gross and net real power generating capability needed for reliability assessment and future plans, we direct the ERO to develop a Work Plan and submit a compliance filing.

1310. The Commission remains concerned that the Reliability Standard is not sufficiently clear because it does not define the test conditions and methodologies for calculating de-rating

[364] Northern Indiana states that the longer the duration, the more stressed the units—and the system—during these testing intervals. For example, Commission staff recommends the use of ambient air temperature and river water temperature as triggering tests to verify generator gross and net real power capability. However, temperature-driven test triggers would result in several neighboring systems in the same region undergoing tests at the same time in order to meet the test criteria. For example, a temperature trigger of 90 degrees Fahrenheit for a net demonstrated capacity test could result in all neighboring generating owners taking their units off of automatic generator control to reach maximum net demonstrated capacity for the test. By taking units off automatic generator control, the generating owners' regulating capabilities are lost.

factors. The Commission does not agree with APPA that NERC should consider modifying this Reliability Standard to provide requirements for this information on an Interconnection-wide basis, in the same manner that IRO–006–3 sets the requirements for transmission loading relief in each Interconnection. We believe, however, that while the overall methodology for verification of generator gross and net real power capability should be the same, test conditions (such as ambient temperature, river water temperature, etc.) can vary.

1311. In the NOPR, the Commission stated that the Reliability Standard could be improved by defining test conditions, *e.g.*, ambient temperature, river water temperature, and methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. With the test information and methodologies, the generator output that can be expected to be available at forecasted weather conditions can be determined. The Commission agrees with Northern Indiana that testing all units at the same time is not feasible. However, the Commission did not propose simultaneous testing. Rather, we direct the ERO to develop appropriate requirements to document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Similarly, we respond to Constellation that any modification of the Levels of Non-Compliance in this Reliability Standard should be reviewed in the ERO Reliability Standards development process.

1312. We repeat our concern that Requirement R2, which specifies that the ''regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval,'' is not clear. The requirement lacks a definition of what approval is required and when the 30-day period starts. Therefore, we direct the ERO to modify this Reliability Standard by adding information that will clarify this requirement.

1313. The Commission neither accepts nor remands MOD–024–1 until the ERO submits additional information. Although the Commission did not propose any action with regard to MOD–024–1, it addressed above a number of concerns regarding the Reliability Standard. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide this information. In the interim, compliance with MOD–024–0 should continue on a voluntary basis, and the Commission considers compliance with it to be a matter of good utility practice.

y. Verification of Generator Gross and Net Reactive Power Capability (MOD–025–1)

1314. MOD–025–1 requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net reactive power capability. The Reliability Standard also requires the regional reliability organization to provide its generator gross and net reactive power capability verification and reporting procedures, and any changes to those procedures, to the generator owners, generator operators, transmission operators, planning authorities and transmission planners affected by the procedure within 30 calendar days of approval of the Reliability Standard.

1315. In the NOPR, the Commission identified MOD–025–1 as a fill-in-the-blank standard that requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net reactive power capability. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD–025–1 until the ERO submits the additional information. In addition, the Commission suggested that MOD–025–1 could be clearer by requiring a minimum reactive power (MVAR) capability throughout a unit's real power operating range. Further, the NOPR stated that requirement R2 provides that the ''regional reliability organizations shall provide generator gross and net real power capability verification within 30 calendar days of approval'' and noted that it is not clear what approval is required and when the 30-day period starts.

i. Comments

1316. APPA agrees that the Commission should not approve this Reliability Standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1317. MidAmerican notes that the Reliability Standard will be clearer if minimum reactive power capability is required throughout a unit's real power operating range. However, making this a Requirement for existing units would be a hardship for units not built with the Requirement in mind. Therefore, MidAmerican suggests that any such requirement should allow existing units to be grandfathered in as they are currently rated so that a new minimum reactive power standard is only applicable to new generating units or units that are being significantly upgraded.

1318. Northern Indiana cautions the Commission against the establishment of a minimum capability, because it could diminish a unit's ability to contribute to Interconnection reliability, and to maintain its own stability. Northern Indiana points out that all generators have reactive capability curves from design manufacturers, and these curves provide operators with a range that is considered by the manufacturer to be a safe operating limit. Northern Indiana contends that the continued use of reactive capability curves is superior to establishment of an MVAR capability, and that operators effectively use these curves to maintain unit stability, while also contributing to the reliability of the Interconnection. Northern Indiana believes that continued reliance on manufacturer reactive capability curves is a technically sound means to achieve the Reliability Standard's stated reliability goal in a manner superior to the establishment of MVAR capability.

1319. Similarly to Northern Indiana, Wisconsin Electric encourages the Commission to withdraw this suggested modifications to NERC's Reliability Standard for several reasons. Wisconsin Electric believes that a requirement to test and verify the minimum reactive capability at multiple points over the operating range as part of the additional minimum MVAR capability requirement would be a significant and unnecessary burden on utilities. In Wisconsin Electric's experience, a reactive power test at a single operating point is sufficient and more practical to achieve.

1320. SoCal Edison recommends that the Commission specifically state the effective date for compliance with each Reliability Standard in its Final Rule. SoCal Edison states that the effective date is critical and gives the example of MOD–025–1, with effective dates phased in over several years after they are adopted by the NERC board of trustees, and well after the date the Final Rule will be issued.

ii. Commission Determination

1321. The Commission will not approve or remand MOD–025–1 until the ERO submits additional information. In order to continue verifying and reporting gross and net reactive power generating capability needed for reliability assessment and future plans,

we direct the ERO to develop a Work Plan as defined in the Common Issues section.

1322. We disagree with commenters that verifying generator reactive capability is a particularly difficult issue. The capability of generators to produce reactive power is essential for real-time analysis and planning. The Reliability Standard addressing this issue requires a generator to verify reactive capability only at the unit's full MW loading. However, other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary. Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD–025–1 to require verification of reactive power capability at multiple points over a unit's operating range.

1323. We maintain the concern we expressed in the NOPR that Requirement R2 provides that the ''regional reliability organization shall provide generator gross and net reactive power capability verification within 30 calendar days of approval'' and note that it is not clear what approval is required and when the 30-day period starts. We direct the ERO to provide clarification on this requirement.

1324. The Commission neither accepts nor remands MOD–025–1 until the ERO submits additional information. Although the Commission did not propose any action with regard to MOD–025–1, it addresses above a number of concerns regarding the Reliability Standard. We direct the ERO to develop a Work Plan to verify and report on generator gross and net reactive power capability while this Reliability Standard is being modified and to modify this Reliability Standard through the Reliability Standards development process to: (1) Require verification of a reactive power capability at multiple points over a unit's operating range and (2) clarify Requirement R2 with a definition of what approval is needed and when the 30-day period starts.

9. PER: Personnel Performance, Training and Qualifications

1325. The four proposed Personnel Performance, Training and Qualifications (PER) Reliability Standards are applicable to transmission operators, reliability coordinators and balancing authorities with the intention of ensuring the safe and reliable operation of the interconnected grid through the retention of suitably trained and qualified personnel in positions that can impact the reliable operation of the Bulk-Power System. The PER Reliability Standards address: (1) Operating personnel responsibility and authority; (2) operating personnel training; (3) operating personnel credentials and (4) reliability coordination staffing.

a. Operating Personnel Responsibility and Authority (PER–001–0)

1326. PER–001–0 requires that transmission operator and balancing authority personnel have the responsibility and authority to direct actions in real-time. PER–001–0 also requires clear documentation that operating personnel have the responsibility and authority to implement real-time action to ensure the stable and reliable operation of the Bulk-Power System.

1327. In the NOPR, the Commission proposed to approve PER–001–0 as mandatory and enforceable.

i. Comments

1328. APPA agrees that PER–001–0 is sufficient for approval as a mandatory and enforceable Reliability Standard.

1329. ISO–NE supports the adoption of this Reliability Standard provided that the Commission does not mandate that the tasks performed by local control centers be included in the definition of transmission operators. It explains that to do so would suggest that the local control center has independent autonomy in operating the Bulk-Power System, which conflicts with the ''one set of hands on the wheel'' philosophy supported by Order No. 2000 and the operating agreements approved by the Commission to establish ISO–NE as New England's RTO.

ii. Commission Determination

1330. The Commission agrees with the ''one set of hands on the wheel'' philosophy described by ISO–NE as it applies to operations of the Bulk-Power System and has no intention of deviating from it. Nothing in the Commission's proposed modifications outlined in the NOPR in regard to the PER Reliability Standards is intended to conflict with this philosophy. A generic discussion of the local control centers is included in the Applicability Issues section and specific implications to operator training are discussed in PER–002–0.[365]

1331. Accordingly, the Commission approves PER–001–0 as mandatory and enforceable. We find that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.

b. Operating Personnel Training (PER–002–0)

1332. PER–002–0 requires that transmission operator and balancing authority personnel are adequately trained. The Reliability Standard: (1) Directs each transmission operator and balancing authority to have a training program for all operating personnel who occupy positions that either have primary responsibility, directly or indirectly, for the real-time operation of the Bulk-Power System or who are directly responsible for complying with the NERC Reliability Standards; (2) lists criteria that must be met by the training program and (3) requires that operating personnel receive at least five days of training in emergency operations each year using realistic simulations.

1333. In the NOPR, the Commission proposed to approve Reliability Standard PER–002–0 as mandatory and enforceable. In addition, the Commission proposed to direct that NERC submit a modification to PER–002–0 that: (1) Identifies the expectations of the training for each job function; (2) develops training programs tailored to each job function with consideration of the individual training needs of the personnel; (3) expands the applicability to include reliability coordinators, generator operators, and operations planning and operations support staff with a direct impact on the reliable operation of the Bulk-Power System; (4) uses the Systematic Approach to Training (SAT) methodology in its development of new training programs and (5) includes performance metrics associated with the effectiveness of the training program. In addition, the Commission requested comments on the benefits and appropriateness of required ''hands-on'' training using simulators in dealing with system emergencies.

i. General Issues

(a) Comments

1334. EEI supports the Commission's direction for personnel training and generally agrees with the Commission's proposal for PER–002–0. EEI states NERC is developing a new Reliability Standard, PER–005–0, which could be

[365] *See* Applicability Issues: Use of the NERC Functional Model, *supra* section II.C.4.

filed with the Commission as early as July 2007. According to EEI, this new Reliability Standard will respond to the issues raised in the NOPR regarding PER–002–0. EEI notes that the ERO plans to retire Reliability Standards PER–002–0 and PER–004–1 when proposed PER–005–0 is adopted. It recommends that the Commission consider consolidating all training requirements into a single Reliability Standard to simplify the Reliability Standards catalog.

1335. Additional comments received have been grouped as follows: Local control center personnel; applicability to generator operators; applicability to operations planning and operations support staff; implications to small systems; training performance metrics; use of SAT methodology; and use of simulators separately, followed by an overall conclusion and summary.

(b) Commission Determination

1336. EEI's comments concerning a possible PER–005–0 are beyond the scope of this proceeding. The Commission will not require the ERO to consolidate all training requirements into a single Reliability Standard. We believe that such matters should be left to the discretion of the ERO through its Reliability Standards development process.

ii. Local Control Center Personnel

1337. In the NOPR, the Commission noted that decisionmaking and implementation may be performed by separate groups in an ISO or RTO context, as well as other organizations that pool resources.[366] The Commission proposed that all control centers and organizations that are necessary for the actual implementation of the decision or are needed for operation and maintenance made by the ISO, RTO or pooled resource organization should be part of the transmission or generator operator function. Although the NOPR discussed this matter in the context of the Communication (COM) Reliability Standards, the NOPR indicated that the proposal would apply in the training and certification context, as well.[367]

(a) Comments

1338. EEI states that the term ''operating personnel'' as used in the PER group of Reliability Standards needs clarification because it may be interpreted to mean any person with a capability to take a unilateral action that can have a potentially significant effect on the Bulk-Power System. EEI states that the term is open to broad interpretation in actual practice, subject to various contracts, operating agreements and ISO/RTO procedures. It states, for example, a local control center operator may take instructions from and act on those instructions, whereas the ''transmission operator'' under the Functional Model may be viewed as a more centralized authority such as a larger regional system operator. EEI contends that some define local control center as a transmission operator, while others disagree.

1339. ISO–NE states the scope of PER–002–0 need not be expanded because local control center personnel in its footprint implement tasks delegated to them by ISO–NE for operation of designated transmission facilities. NPCC argues that expanding PER–002–0 beyond the entities identified under the NERC Functional Model (*i.e.*, transmission operators, reliability coordinators and balancing authorities) will require substantial cost and time but add little value. It states that there are no certification exams for any entities other than transmission operators, reliability coordinators and balancing authorities and to develop and implement such exams and to have the additional personnel certified would take several years. It also states that these personnel already function under the authority of NERC-certified operators and act only at the direction of certified operators. It concludes that an entity that does not exercise operational authority should not be subject to the same requirements as the decisionmaker.

1340. Northern Indiana states that it is not uncommon in the industry for employees who perform switching operations to be supervised by NERC-certified operators and that such employees are subject to round-the-clock review by, and communication with, their NERC-certified transmission operators. Similarly, SoCal Edison notes that large utilities can have operators strategically located throughout a vast service territory at switching centers with SCADA capability and that these operators follow the directives of one control center responsible for Bulk-Power System reliability. SoCal Edison disagrees that the operators of these switching centers, simply because the switching center has SCADA capability, must be NERC-certified.

1341. LPPC states that the training and certification requirements should apply only to transmission and generation personnel that are located in the transmission control center (*i.e.*, responsible for real-time Bulk-Power System operations). It argues that transmission and generation operation employees that are located in remote locations that are not directly involved in the real-time scheduling of transactions or Bulk-Power System monitoring and control do not need to be certified for real-time operations because they are not involved in the type of functions in which regimented training in the Reliability Standards would be useful. It suggests that a bright line should be drawn between the training of actual system operators and the training for operators of generation plants that are not responsible for scheduling. LPPC also states that the Commission should clarify the scope of training that the transmission control center real-time operations personnel should receive.

1342. Entergy asserts that the training program should be tailored to the functions local control center operators, generator operators and operations planning staff perform that impact the reliable operation of the Bulk-Power System for both normal and emergency operations.

(b) Commission Determination

1343. In our discussion above regarding the Functional Model, we emphasized our concern that there should be no unintentional gaps or redundancies in responsibility for compliance with the Requirements of Reliability Standards. This concern arises particularly in the context of RTOs, ISOs and other pooled resources that may have separate divisions performing decisionmaking functions and implementing functions within the transmission operator classification. The topic of training is one such area of concern. While PER–002–0 applies to transmission operators, it is important for reliability that personnel involved in both decisionmaking and implementation receive proper training.

1344. Clearly, in a region where an RTO or ISO performs the transmission operator function, its personnel with primary responsibility for real-time operations must receive formal training pursuant to PER–002–0. In addition, personnel who are responsible for implementing instructions at a local control center also affect the reliability of the Bulk Power System. These entities may take independent action under certain circumstances, for example, to protect assets, personnel safety and during system restorations. Whether the RTO or the local control center is ultimately responsible for compliance is a separate issue addressed above, but regardless of which entity registers for that responsibility, these local control center

[366] NOPR at P 236–37.

[367] *Id.* at P 237, 779.

employees must receive formal training consistent with their roles, responsibilities and tasks. Thus, while we direct the ERO to develop modifications to PER–002–0 to include formal training for local control center personnel, that training should be tailored to the needs of the positions.

1345. As noted by SoCal Edison, there are different operating structures and therefore there is a need to clarify to which control centers we direct the Reliability Standard apply. For example, for a large utility within an RTO or ISO footprint there may be one centrally-located control center whose function is to supervise several distributed control centers, each with remote monitoring and control capability. In this type of structure, the personnel of the centrally-located control center should receive formal training in accordance with the Reliability Standard. Personnel at the distributed control centers also need to be trained, but the responsibility for this training is outside the scope of the Reliability Standard.[368]

1346. Another organizational structure, typically representative of relatively smaller entities, consists of a single control center that implements operating instructions from its transmission operator, *e.g.*, an RTO, ISO or pooled resource. Similar to the discussion above, operators at these control centers also may take independent action to protect assets, safety and system restoration. Such control center personnel must also receive formal training pursuant to PER–002–0.

1347. Consistent with the comments of SoCal Edison and Northern Indiana, the Commission understands that it is common practice to have traveling operators located in the local control centers who carry out field switching operations and station inspections at the direction of the local control center operators. These personnel are not involved with the transmission operator at the ISO or RTO or at organizations with pooled resources, and as such, should not be subject to Reliability Standard PER–002–0.

1348. The Commission disagrees with those commenters who contend that, because operators at local control centers take direction from NERC-certified operators at the ISO or RTO, they do not need to be addressed by the training requirements of PER–002–0. Rather, as discussed above, these operators maintain authority to act independently to carry out tasks that require real-time operation of the Bulk-Power System including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration.

1349. Several commenters express concern about requiring local control center operators to become fully trained to the same extent as transmission operators, balancing authorities and reliability coordinators. This is not the Commission's intent. As we stated in the NOPR, the proposed modifications do not imply a ''one-size-fits-all'' approach but rather ensure the creation of training programs that are structured and tailored to the different functions and needs of the personnel involved.[369] Therefore the Commission agrees with Entergy that the training program should be tailored to the functions local control center operators, generator operators and operations planning staff perform that impact the reliable operation of the Bulk-Power System for both normal and emergency operations.

iii. Applicability to Generator Operators

1350. The Commission proposed in the NOPR a modification to PER–002–0 to include real-time operations personnel from reliability coordinators, generator operators, operations planning and operations support staff in training programs with a time-phased effective date.[370]

(a) Comments

1351. PG&E and FirstEnergy support the Commission's goal of ensuring appropriate training for generator operators. FirstEnergy, however, believes that there is some confusion between the Functional Model and the Reliability Standard requirements concerning the generator operator classification. FirstEnergy explains that, in some contexts, ''generator operator'' refers to operations personnel who are centrally-located at a generation control center (*i.e.*, fleet operators) while in other contexts it refers to generator operators located at the generation plant (*i.e.*, unit operator). Further, according to FirstEnergy, the NERC glossary defines ''generator operator'' as the entity that operates generating unit(s) and performs the functions of supplying energy and interconnected operations services. FirstEnergy requests that the Commission direct NERC to revise the Reliability Standard to recognize this distinction.

1352. Other commenters, including Xcel, California PUC and Entergy, state that the Reliability Standard should not apply to generator operators. Xcel argues that generator operators take their direction from transmission operators, balancing authorities and reliability coordinators, which limits their ability to exercise independent action impacting the reliability of the Bulk-Power System. Entergy argues that expanding the applicability to generator operators would provide little benefit to those personnel in the performance of their own functions, and could distract them from those functions. It also argues that such training would be extremely costly and would divert necessary resources from more important reliability objectives.

1353. California PUC states that the requirement to include power plant operators in the applicability of this Reliability Standard exceeds anything contemplated in the regulation of the Bulk-Power System under previous NERC guidelines and what is authorized by statute. It contends that impacts of generator operator actions on the Bulk-Power System are of a much smaller magnitude and consequence than those of system operators. Further, it states that other authorities, such as balancing authorities and state governments, may have acted in regard to training of power plant operators and, therefore, the Commission should not act where other authorities have already done so. In a similar vein, the Nevada Companies state that the activities of generating station operations personnel are limited to the confines of the specific generating station. Knowledge of or exposure to interconnected grid operating principles is simply not applicable to the tasks normally performed at the generating stations.

1354. Reliant states that the proposed modification fails to clarify how generator operators are to satisfy the training program requirement or the scope of generator operator personnel that must be trained. It states that the proposed modification could be interpreted to require generator operators to train the plant operator as well as the dispatcher in the generator operator's local control center. Reliant believes, however, that plant operators should not be subject to the Reliability Standard's training program requirement because personnel employed in plant operating positions are trained in the operation of plant equipment and take direction with respect to the operation of the plant from management personnel as well as from the local control center. Accordingly, it reasons that, because

[368] The Commission expects the entity registered as the transmission operator to ensure that these personnel are competent for the tasks that they perform.

[369] *See* NOPR at P 773, 775.

[370] *Id.* at P 772.

these employees take direction with respect to plant operations from elsewhere, they do not have primary responsibility for the real-time operation of the Bulk-Power System and should not be responsible for complying with Reliability Standards. Reliant suggests that PER–002–0 should specifically target generator operator personnel that develop dispatch instructions and the Reliability Standard should be modified to accommodate generator operator entities that are members of ISOs and RTOs with established NERC-approved certification programs. However, it should exclude those personnel who simply take direction on plant operations.

1355. Dynegy, MISO and Wisconsin Electric state that these Reliability Standards should not be extended to all real-time operation positions of a generator operator. They state that many real-time operation positions are staffed by long-tenured union personnel who routinely operate generating units and take directions from a centralized generation control center or the local RTO/ISO. They analogize this type of certification and training requirement with requiring the outside field force of a transmission operator, including positions that operate and switch electric transmission lines pursuant to instructions from a centralized transmission control group, to be NERC-certified. Dynegy and MISO support a more limited extension of these Reliability Standards to real-time operation personnel located in a centralized generation control center that interfaces with the plants and the local RTO/ISO but not to personnel at the plant level.

1356. Some commenters address the appropriate scope of training for generator operators. For example, MidAmerican states that experience and knowledge necessary for transmission operators may go well beyond what is needed for generation operations. It contends that a NERC-approved training course specific to these functions would be an appropriate alternative. Entergy comments that, if training of generator operator personnel is required, it should focus on the functions generator operators must perform, not on the functions that others perform. SDG&E states that training for generator operators and others who may directly impact the reliable operations of the Bulk-Power System need not be identical to or as extensive as that required of transmission system operators, but should be tailored in scope, contents and duration so as to be appropriate to the personnel and the object of promoting system reliability.

1357. FirstEnergy states that there are no universal certification or training programs for generator operators; therefore a reasonable transition period should be established to allow time for generator operators to comply with this Reliability Standard. It also states that nuclear units are already subject to NRC training requirements and that compliance with NRC requirements should satisfy this Reliability Standard.

1358. APPA, Process Electricity Committee and TAPS are concerned that, unless a size limitation is included for the generator operators, a substantial number of generator operator personnel will have to be enrolled in training programs. They argue that while a generator plays an important role in the reliable operations of the bulk electric system, the generator operator takes commands from the transmission operator, balancing authority or reliability coordinator. TAPS opposes the expanded applicability, especially in the case of small systems, because it believes that the requirement would be costly with no benefits to reliability.

1359. Process Electricity Committee is concerned about the effect of the expanded requirements on end users who have on-site generation. It argues that the training requirements would present an added cost for end users with no apparent added benefit and that, in the long term, end users may be discouraged from developing on-site generation, which in turn would leave industrial electricity users more vulnerable to failures elsewhere on the energy grid.

(b) Commission Determination

1360. The Commission explained in the NOPR that transmission operators and balancing authorities are not the only entities that have operating personnel in positions that directly impact the reliable operation of the Bulk-Power System; and included generator operators among those that have such an impact.[371] Xcel and others oppose extending the applicability of PER–002–0 to generator operators, because they take directions from balancing authorities and others, which limits their ability to impact reliability. Although a generator may be given direction from the balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action. Further, if communication is lost, the generator operator personnel should have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System. Thus, we direct the ERO to develop a modification to make PER–002–0 applicable to generator operators.

1361. We agree with FirstEnergy and others that some clarification is required regarding which generator operator personnel should be subject to formal training under the Reliability Standard. As noted above, a generator operator typically receives instructions from a balancing authority. Some generator operators are structured in such a way that they have a centrally-located dispatch center that receives direction and then develops specific dispatch instructions for plant operators under their control. For example, a balancing authority may direct a centrally-located dispatch center to deliver 300 MW to the grid, and the dispatch center would determine the best way to deliver that generation from its portfolio of units. In this type of structure, it is the personnel of the centrally-located dispatch center that must receive formal training in accordance with the Reliability Standard. Plant operators located at the generator plant site also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.[372]

1362. Other generator operators may be structured in such a way that the dispatch center and the single generation plant are at the same site. In this structure as well, some personnel will perform dispatch activities while others are designated as plant operators. Again, it is the dispatch personnel that must receive formal training in accordance with the Reliability Standard. Plant operators also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.

1363. We disagree with Nevada Companies, Xcel and others that assert that generator operator training will provide limited benefit. Rather, we conclude that, with the above focused direction regarding the applicability of the Reliability Standard to generator operator personnel, the benefits to the Bulk-Power System will be maximized and the cost of formal training limited. Further, our direction addresses California PUC's concerns regarding application to plant operators. In any event, the existence of local training requirements in some regions does not supplant the need for uniform training requirements for all generator operators

[371] NOPR at P 771.

[372] The Commission expects the entity registered as the generator operator to ensure that plant operators are competent for the tasks that they perform.

developed in a Reliability Standard with continent-wide applicability.

1364. Further, the Commission agrees with MidAmerican, SDG&E and others that the experience and knowledge required by transmission operators about Bulk-Power System operations goes well beyond what is needed by generation operators; therefore, training for generator operators need not be as extensive as that required for transmission operators. Accordingly, the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability. Thus, in addition to modifying the Reliability Standard to identify generator operators as applicable entities, we direct the ERO to develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel.

1365. FirstEnergy states that nuclear plant operators are already subject to NRC training requirements and thus suggests that compliance with NRC requirements should satisfy this Reliability Standard. FirstEnergy does not identify the content of the NRC training requirements, and the Commission is unaware whether the NRC training requirements adequately address the interaction between a nuclear power plant and the Bulk-Power System. Accordingly, without drawing any conclusion on the matter, the Commission directs that the ERO consider FirstEnergy's comments in the Reliability Standards development process.

1366. Commenters' concerns regarding the need for a size limitation on generator operators should be satisfied by our determination that the applicability of particular entities should be determined based on the ERO compliance registry criteria, which APPA and TAPS support. We believe that limiting the applicability of Reliability Standards to NERC's definition of bulk electric system will alleviate much of Process Electricity Committee's concern regarding the effect of the expanded requirements on end users who have on-site generation. For larger end users who have on-site generation, the Commission believes that there is an added benefit to including them in the Reliability Standards because they sell into the market and should be treated on a similar basis as any other generator of a similar size.

iv. Applicability to Operations Planning and Operations Support Staff

1367. As mentioned above, the Commission proposed in the NOPR to direct the ERO to develop a modification to PER–002–0 to require training of operations planning and operations support staff of transmission operators and balancing authorities who have a direct impact on the reliable operation of the Bulk-Power System.

(a) Comments

1368. Several commenters, including EEI and APPA, oppose the proposed applicability of the Reliability Standard to operations planning and operations support staff. Other commenters contend that the Commission's proposal is ambiguous and should be clarified.

1369. EEI states that the extension of the applicability to ''operations support personnel'' could result in a dramatic expansion of industry training requirements with uncertain benefits to system reliability. It requests that the Commission reconsider this proposal or provide some additional clarity on the definition of the term. APPA also expresses concern about expanding the applicability to operations planning and operations support staff, especially if the Commission adopts its proposed interpretation of the bulk electric system because this would become quite onerous for small utilities. Wisconsin Electric states that the Commission's proposal does not address how to identify the operations planning and operations support personnel who would be subject to the Reliability Standard and how to develop compliance measures for them. It contends that the proposed modification is ambiguous and should not be implemented.

1370. Avista states that individuals who are responsible for assessing a company's compliance with the Reliability Standards may simply have an administrative and coordination role, but have no direct responsibility for reliable operations of the Bulk-Power System. It argues that such individuals, while operations support staff, should not be subject to the proposed Reliability Standard. It therefore requests that the Commission clarify that personnel subject to the Reliability Standard *may* include operations planning and operations support staff.

1371. Entergy believes it is unnecessary to require all staff supporting the transmission operator to be trained in the transmission operator's Reliability Standards responsibilities. It states that as long as the supporting personnel work under the direction of a NERC-certified transmission operator, there is no need for duplicative training for supporting personnel. Entergy comments that, if such training is required, it should focus on the functions operations planning and operations support staff must perform, not on the functions that others perform.

1372. Northern Indiana states that expanding application of the Reliability Standard to operations support staff ''with a direct impact on the reliable operation of the Bulk-Power System'' is ambiguous. It states that NERC surveyed certified operators for its job function analysis related to this Reliability Standard with results due at the end of January 2007. Northern Indiana recommends that the results of this survey be considered in the development and clarification of this proposed Reliability Standard. Further, Northern Indiana is concerned about which specific job functions will be addressed and which will be exempt, and about what ''direct'' versus ''indirect'' impact means.

(b) Commission Determination

1373. The Commission directs the ERO to develop a modification to PER–002–0 that extends applicability to the operations planning and operations support staff of transmission operators and balancing authorities, as clarified below. Most commenters express concern about extending the applicability of the Reliability Standard because they believe ''operations planning'' and ''operations support'' are not well-defined and could encompass a significant number of operations personnel. In the NOPR, the Commission stated that the Reliability Standard should apply to operations planning and operations support staff that have a direct impact on the reliable operation of the Bulk-Power System.[373] We clarify that these personnel include those who carry out outage coordination and assessments in accordance with Reliability Standards IRO–004–1 and TOP–002–2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO–005–1 and TOP–004–0. The Commission directs the ERO to include in PER–002–0, personnel who carry out the above functions.

1374. In addition, the Commission is aware that the personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages, are available, up-to-date in terms of system

[373] NOPR at P 780.

data and produce useable results can also have an impact on the Reliable Operation of the Bulk-Power System. Because these employees' impact on Reliable Operation is not as clear, we direct the ERO to consider, through the Reliability Standards development process, whether personnel that perform these additional functions should be included in mandatory training pursuant to PER–002–0.

1375. APPA and EEI oppose the proposed extension of the Reliability Standard to operations planning and operations support staff, claiming that it could dramatically expand industry training requirements with uncertain benefits to system reliability. Our clarification above adequately addresses these concerns because we have identified a specific set of such personnel that have a direct impact on reliable operations. With the above clarification, our directive is not as expansive as EEI and APPA contemplate, and is more clearly connected with Bulk-Power System reliability. Further, since the Commission is not adopting the proposed interpretation of the ERO's definition of bulk electric system, as discussed in the Applicability section above, the directed modification to PER–002–0 should not be onerous to small entities as suggested by APPA.

1376. Several commenters express concern that the operations planning and operations support staffs will be required to be trained on the transmission operators' responsibilities. The Commission clarifies that this is not the case. Training programs for operations planning and operations support staff must be tailored to the needs of the function, the tasks performed and personnel involved.

v. Training Performance Metrics

1377. In the NOPR, we noted the assertion by ISO/RTO Council that there is no definition for ''adequately trained operating personnel.'' ISO/RTO Council suggested adoption of performance metrics to ensure that training results in competent operating personnel.[374] The Commission agreed and proposed to require that the ERO modify PER–002–0 to include performance metrics to assess the effectiveness of the training program. The Commission also stated that such performance metrics are not a substitute for an SAT developed training program.

(a) Comments

1378. Xcel does not agree that performance metrics should be included as part of this Reliability Standard. While it believes performance metrics are generally useful, it states that in this case it would be difficult to develop the appropriate metrics. MidAmerican believes that the proposed performance metrics are not essential to ensuring the appropriateness of training because the Reliability Standard already requires NERC approval of all training activities, and specifically requires training in certain areas.

1379. MISO and Wisconsin Electric state that it is unclear how a Reliability Standard to measure the effectiveness of a training program would apply to an organization that contracts for training services, and that there are many training requirements found in other Reliability Standards covering the topics and amount of training. They argue that the proposed modification is overly-prescriptive and deviates from a fundamental training concept that training should be tailored to the organization and to the individual.

(b) Commission Conclusion

1380. Xcel, MISO and MidAmerican state that performance metrics to assess the effectiveness of training programs are unnecessary. The Commission believes that, if quantifiable performance metrics can be developed to gauge the effectiveness of a Reliability Standard, these performance metrics should be developed, tracked and used to continually improve an applicable entity's performance and the Reliability Standard itself. The Commission directs the ERO to explore the feasibility of developing meaningful performance metrics for assessing the effectiveness of training programs, and if feasible, to develop such metrics for the Reliability Standard as part of the Reliability Standards development process.

vi. Use of Systematic Approach to Training (SAT) Methodology

1381. In the NOPR, the Commission required the ERO to use the SAT methodology in identifying the requirements for a training program because SAT is a proven approach to: identify the tasks and associated skills and knowledge necessary to accomplish those tasks; determine the competency levels of each operator to carryout those tasks; determine the competency gaps; and design, implement and evaluate a training plan to address each operator's competency.[375]

(a) Comments

1382. ISO–NE states that the use of SAT methodology should not be mandated and that responsible entities under this Reliability Standard should be allowed the flexibility to use the most appropriate training methodology available. Northern Indiana requests clarification on about our proposal on the use of SAT methodology.

(b) Commission Determination

1383. The Commission understands that the new operator training Reliability Standard PER–005–1–0 currently under development by the ERO would endorse the use of SAT. In response to ISO–NE, training based on SAT is a proven approach to identify the skills and knowledge necessary to accomplish particular tasks, evaluate each operator's competency to carry out those tasks, determine any competency competency gaps, and design, implement and evaluate a training plan to address such gaps. Since SAT is the most appropriate training methodology available, we believe this addresses ISO–NE's comments. Northern Indiana requests clarification about the details of our proposal for SAT methodology. The Commission has not directed how the SAT methodology should be implemented, but we expect it to be developed through the Reliability Standards development process. We encourage Northern Indiana to become involved in the process. Thus, we adopt the NOPR proposal to direct that the ERO develop a modification to PER–002–2 (or a new Reliability Standard) that uses the SAT methodology.

vii. Use of Simulators for Training

1384. The Commission explained in the NOPR that Requirement R4 of the Reliability Standard requires training in emergency operations using realistic simulations of system emergencies and noted that there are various options available for providing operator training simulator capability, including contracting for this service from others who have developed the capability. The Commission requested comments on the benefits and appropriateness of required ''hands-on'' training using simulators in dealing with system emergencies.[376]

(a) Comments

1385. While most commenters recognize the benefits of simulator training, they differ on whether simulator training should be mandatory.

1386. NERC comments that there can be significant value gained by training operating personnel for emergencies under realistic conditions using training simulators and requests that comments on this matter be directed to the

[374] *Id.* at P 776.

[375] *Id.* at P 775.

[376] *Id.* at P 778.

Reliability Standards development process for consideration. APPA believes that significant reliability benefits could result from the use of simulators by reliability coordinators, transmission operators and balancing authorities that have operational control over a significant portion of load and resources. It does not believe, however, that requiring simulator training for smaller entities that do not have operational control over facilities that manage SOLs and IROLs would be an effective use of resources. APPA supports NERC's investigating the benefits of simulator training but recommends that any training requirements closely consider the costs and benefits of simulator training.

1387. SoCal Edison and MISO state that, although simulators are valuable training tools, not all entities should be compelled to have simulators. MISO comments that simulators will become even more critical in the coming years as experienced operators, with first-hand knowledge of their respective systems, retire. Recognizing that not every company can or should build a simulator because of the resources simulators require, MISO suggests that the Reliability Standards codify a requirement for operators of companies that do not own a simulator to have access to a training simulator. MISO states that while simulators are valuable training resources, focusing emergency training solely on full-scale simulators may lead to problems when unforeseen situations arise. It reasons that generic, low-cost simulators that teach concepts are a valuable training resource for developing skills transferable to events that do not follow a script.

1388. SDG&E states that simulators would enhance the overall training experience but cautions that simulators that accurately model individual systems are resource-consuming while less resource-consuming, generic simulators may not mirror the trainee's actual system. As such, it believes that the use of simulators should be encouraged but not mandated. Similarly, International Transmission contends that simulators are a useful tool in the training of operators and support personnel. However it cautions that simulators are not the only means to provide realistic simulation-based training. It argues that because alternative simulation-based training means are available and because dedicated training simulators are very expensive, the use of dedicated training simulators should not be required under the Reliability Standards.

1389. Otter Tail states that full-scale simulators are effective but costly to develop and labor intensive to maintain. It recommends that full-scale simulators should be an option but not a requirement for small entities. It proposes instead that the Commission allow small entities to continue to use training aids such as generic operator training simulators, EXCEL-based interactive training tools and table-top training exercises. Likewise, Alcoa also does not believe that simulators are necessary to provide operating personnel with training for system emergencies. It supports alternative training methods, such as table-top exercises or realistic simulated exercises that take into account the physical and electrical characteristics of the trainee's system. Further, it believes that costs associated with simulators would not be justified by the impact on reliability.

1390. Xcel states that to the extent that Reliability Standard PER–002–0 is applicable to generator operators, the industry should be able to develop its own ways of administering training instead of being required to develop simulators.

(b) Commission Determination

1391. Most commenters including NERC agree that hands-on training using simulators can add significant value to training for emergencies. Yet, we share the commenters' concerns regarding the high cost to develop and maintain full-scale simulators and take these concerns into consideration. The Commission finds that significant reliability benefits may be derived from requiring simulator training for reliability coordinators, transmission operators and balancing authorities that have operational control over a significant portion of load and generation.

1392. This does not mean that these entities must develop and maintain full-scale simulators but rather they should have access to training on simulators. Further, because the cost is likely to outweigh the reliability benefits for small entities, the Commission agrees with Alcoa and Otter Tail that small entities should continue to use training aids such as generic operator training simulators and realistic table-top exercises. Accordingly, the Commission directs the ERO to develop a requirement for the use of simulators dependent on the entity's role and size, as discussed above.

viii. Summary of Commission Determination

1393. The Commission notes that no commenters specifically addressed the proposed modifications directing the ERO to expand the Applicability section to include reliability coordinators, and to identify the expectations of the training for each job function and develop training programs tailored to each job function with consideration of the individual training needs of the personnel. However, in responding to the proposals to expand the applicability of the Reliability Standard, many commenters acknowledged the need to have clear training expectations and training programs tailored to specific job functions. The Commission finds that these two modifications will enhance the training by focusing on expectations and tailoring the training to specific job functions; therefore, the Commission adopts these modifications to the Reliability Standard.

1394. Accordingly, the Commission approves Reliability Standard PER–002–0. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to PER–002–0 through the Reliability Standards development process that: (1) Identifies the expectations of the training for each job function; (2) develops training programs tailored to each job function with consideration of the individual training needs of the personnel; (3) expands the Applicability section to include (a) reliability coordinators, (b) local transmission control center operator personnel (as specified in the above discussion), (c) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System and (d) operations planning and operations support staff who carry out outage planning and assessments and those who develop SOLs, IROLs or operating nomograms for real-time operations; (4) uses the Systematic Approach to Training (SAT) methodology in its development of new training programs and (5) includes the use of simulators by reliability coordinators, transmission operators and balancing authorities that have operational control over a significant portion of load and generation.

1395. Further, the Commission directs the ERO to determine whether it is feasible to develop meaningful performance metrics associated with the effectiveness of a training program required by PER–002–0 and, if so, develop such performance metrics. The Commission also directs the ERO to consider through the Reliability Standards development process, whether personnel that support EMS applications as discussed above should be included in mandatory training pursuant to the Reliability Standard.

c. Operating Personnel Credentials (PER–003–0)

1396. PER–003–0 requires transmission operators, balancing authorities and reliability coordinators to have NERC-certified staff for all operating positions that have a primary responsibility for real-time operations or are directly responsible for complying with the Reliability Standards. NERC grants certification to operating personnel through a separate program documented in the NERC System Operator Certification Manual and administered by an independent personnel certification governance committee.

1397. In the NOPR, the Commission proposed to approve Reliability Standard PER–003–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PER–003–0 that: (1) Includes generator operators as applicable entities; (2) specifies the minimum competencies that must be demonstrated to become and remain a certified operator; and (3) identifies the minimum competencies operating personnel must demonstrate to be certified.

i. Comments

1398. In addressing this Reliability Standard, many commenters made the same arguments they made in connection with the operator training Requirements set forth in Reliability Standard PER–002–0. Comments specifically relevant to operator certification are reproduced here for completeness.

1399. EEI, FirstEnergy and PG&E agree that the Reliability Standard should apply to generator operators. FirstEnergy believes that the Functional Model and the Reliability Standards development process should be used to clarify any confusion about which generator operator and transmission operator functions are addressed under this Reliability Standard. To further reduce confusion and the need for potentially duplicative training, EEI and PG&E comment that operators should not be required to maintain multiple certifications. SDG&E states that new certification obligations for generator operators must be tailored to the needs of the function and should reflect the limited opportunities of generator operators to have an impact on system reliability. Thus, it argues that generator operators should not be subject to the same certification requirements as transmission operators. MidAmerican echoes this point and adds that minimum competencies are currently adequately demonstrated by the completion of NERC-approved annual certification tests. MidAmerican believes that applicable tests should be tailored to specific job duties to ensure effectiveness and Reliability Standard compliance.

1400. Dynegy, MISO, Reliant and Wisconsin Electric are concerned about extension of this Reliability Standard to generator operators if it results in every power plant control room being staffed by NERC-certified operators. Dynegy supports a limited extension of the Reliability Standard to real-time operational personnel located in a centralized generation control center that interfaces with the plants and the local RTO/ISO. Reliant believes that, under certain circumstances, the dispatcher in the generator operator's local control center should not be subject to NERC certification requirements. It explains that, for example, in PJM the dispatcher in a generator operator local control center is a PJM-certified generation dispatcher and that, like the employees in plant operating positions, these dispatchers do not take unilateral action but instead act only upon PJM's instructions.

1401. LPPC states that certification requirements for real-time operations Reliability Standards should only be required for transmission and generation personnel that are located in the transmission control center (*i.e.*, responsible for real-time Bulk-Power System operations). It argues that transmission and generation operation employees that are located in remote locations that are not directly involved in the real-time scheduling of transactions or Bulk-Power System monitoring and control do not need to be certified for real-time operations Reliability Standards because they are not involved in the type of functions in which regimented training in the Reliability Standards would be useful. LPPC states that requiring certification would be an inefficient result and would distract these personnel from their own highly-specialized tasks.

1402. Although APPA states that PER–003–0 is sufficient for approval as a mandatory and enforceable Reliability Standard, it opposes the proposed modification to make generator operators subject to the Reliability Standard. Alcoa, Entergy, Northern Indiana and Xcel also oppose subjecting generator operators to the Reliability Standard. Given that there is no size limitation limiting applicability for generator operators, APPA asks the Commission to reconsider the proposed modification and, instead, allow the applicability of PER–003–0 to generator operators to be considered through the Reliability Standards development process. Alcoa disagrees with the proposed modification because generator operators take direction from a NERC-certified transmission operator, balancing authority or reliability coordinator and do not operate independently of those entities. Similarly, Xcel states generator operators have limited ability to take independent action that affects Bulk-Power System reliability. It also states that it is not clear whether ''generator operator'' means plant operator or the transmission operator responsible for generation.

1403. Northern Indiana and SoCal Edison oppose a certification requirement for all real-time operating positions in a transmission control center that performs switching operations via SCADA for the Bulk-Power System, because these personnel are supervised by NERC-certified operators. Northern Indiana states that the costs would far outweigh the reliability benefits, if any, that would result from such a certification requirement. SoCal Edison recommends that PER–003–0 apply to operators who have the authority and are empowered to exercise independent judgment, and who take or direct actions to secure Bulk-Power System reliability. It recommends that operators who switch Bulk-Power System facilities when their actions are approved and overseen by certified operators should be excluded.

1404. APPA states that if it is required to send its employees for NERC training and certification, it would risk losing those employees to larger utilities that can afford to pay more, simply because those employees would have acquired a desirable occupational credential. It argues that given the substantial workforce issues facing public power systems in the next few years, imposing unneeded certification requirements could exacerbate an already challenging labor force situation.

1405. Northern Indiana adds that because some of these employees are members of labor unions and subject to existing collective bargaining agreements, it would have to renegotiate these agreements to provide for the certification of these employees, and to provide for the hiring of relief staff necessary to permit these employees to maintain their certification.

1406. PG&E states that, once the certification requirements are developed by NERC and approved by the Commission, sufficient time must be permitted for generator operators to attain the necessary certification. It argues that time will be needed to

develop the process, create appropriate documentation and perform training for appropriate personnel. PG&E contends that generator operators should not be penalized for failing to achieve certification if they do not have a reasonable period of time to implement the training programs.

1407. EEI believes that the ERO's Reliability Standards development process should be used to sort out the applicability issues. It states that using this process will allow for sufficient clarity to reduce the risk of confusion and thus prevent the need for interpretations that could change over time. EEI believes this is especially important with this PER class of Reliability Standards because operators should have unambiguous guidance on what they are expected to do. It states that the Reliability Standards should be written so that operating personnel clearly understand their roles and responsibilities, and whether or not a specific certification is required. EEI also states that operators should not be required to maintain multiple certifications.

ii. Commission Determination

1408. Northern Indiana and APPA raise persuasive arguments regarding labor relations and labor retention issues that may arise if generator operators are required to be NERC-certified. The Commission understands theses concerns and is persuaded not to require generator operators or transmission operators at local control centers to be NERC-certified at this time. In addition, the Commission understands that there are some long tenured unionized transmission operators who are very capable operators but who are unable to secure certification. This is not a new problem and has been addressed in various collective bargaining negotiations through grandfathering such capable operators who are unable to become certified. However, the Commission directs that if grandfathering is implemented, the entity must attest that the operators are competent. The Commission directs the ERO to consider grandfathering certification requirements for these personnel so that the industry can retain the knowledge and skill of these long-tenured operators. Personnel that are subject to such grandfathering still must comply with applicable training requirements pursuant to PER–002–0.

1409. No comments were received on the proposed modifications to direct the ERO to modify the Reliability Standard to specify the minimum competencies that must be demonstrated to become and remain a certified operator and to identify the minimum competencies operating personnel must demonstrate to be certified. The Commission finds that these modifications improve the Reliability Standard by focusing on necessary competencies. Accordingly, the Commission directs the ERO to develop these modifications to the Reliability Standard.

1410. We find that the Reliability Standard serves an important reliability goal in requiring applicable entities to staff all operating positions that have a primary responsibility for real-time operations or are directly responsible for complying with the Reliability Standards with NERC-certified staff. Accordingly, the Commission approves Reliability Standard PER–003–0. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to PER–003–0 through the Reliability Standards development process that: (1) Specifies the minimum competencies that must be demonstrated to become and remain a certified operator and (2) identifies the minimum competencies operating personnel must demonstrate to be certified. The Commission also directs the ERO to consider grandfathering certification requirements for transmission operator personnel in the Reliability Standards development process.

d. Reliability Coordination—Staffing (PER–004–1)

1411. PER–004–1 ensures that reliability coordinator personnel are adequately trained, NERC-certified and staffed 24-hours a day, seven days a week, with properly trained and certified individuals.[377] Further, reliability coordinator operating personnel must have a comprehensive understanding of the area of the Bulk-Power System for which they are responsible.

1412. In the NOPR, the Commission proposed to approve Reliability Standard PER–004–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to PER–004–0 that: (1) Includes formal training requirements for reliability coordinators similar to those addressed under the personnel training Reliability Standard PER–002–0; (2) includes requirements pertaining to personnel credentials for reliability coordinators similar to those in PER–003–0 and (3) includes Measures and Levels of Non-Compliance that address staffing requirements and the requirement for five days of emergency training.

i. Comments

1413. APPA notes that the revised Reliability Standard PER–004–1 filed by NERC on November 15, 2006 partially fulfills the directive to include Measures and Levels of Non-Compliance. It states that NERC should be directed to include Measures and Levels of Non-Compliance related to all Requirements.

1414. FirstEnergy seeks revisions to the terms ''shall have a comprehensive understanding'' and ''shall have extensive knowledge.'' It states that it will be difficult for entities to demonstrate compliance with these terms. In addition, FirstEnergy suggests that the reliability coordinator staffing requirements should be located in the IRO Reliability Standards.

1415. Xcel states that emergency training requirements should be expressed in hour increments rather than days to allow for flexibility in scheduling training and coordinating with rotating shift schedules.

ii. Commission Determination

1416. No comments were received on the proposed modifications to include formal training requirements for reliability coordinators similar to those addressed under the personnel training Reliability Standard PER–002–0 and to include requirements pertaining to personnel credentials for reliability coordinators similar to those in PER–003–0. The Commission finds that these modifications will improve the Reliability Standard because they include training requirements for the reliability coordinator who has the highest level of authority to assure Reliable Operation of the Bulk-Power System. Accordingly, the Commission directs the ERO to develop modifications to the Reliability Standard that address these matters.

1417. With regard to APPA's comments, consistent with our discussion above regarding Measures and Levels of Non-Compliance, we leave it to the discretion of the ERO whether it is necessary that each Requirement of this Reliability Standard have a corresponding Measure.

1418. We find that the Reliability Standard adequately addresses reliability coordinator staffing. Accordingly, the Commission approves Reliability Standard PER–004–1. In

[377] In its November 15, 2006, filing, NERC submitted PER–004–1, which supercedes the Version 0 Reliability Standard. PER–004–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, PER–004–1.

addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification through the Reliability Standards development process to PER–004–1 that: (1) Includes formal training requirements for reliability coordinators similar to those addressed under the personnel training Reliability Standard PER–002–0 and (2) includes requirements pertaining to personnel credentials for reliability coordinators similar to those in PER–003–0. Further, we direct the ERO to consider the suggestions of FirstEnergy and Xcel in the Reliability Standards development process.

10. PRC: Protection and Control

1419. Protection and Control systems (PRC) on Bulk-Power System elements are an integral part of reliable grid operation. Protection systems are designed to detect and isolate faulty elements on a system, thereby limiting the severity and spread of system disturbances, and preventing possible damage to protected elements. The function, settings and limitations of a protection system are critical in establishing SOLs and IROLs. The PRC Reliability Standards apply to transmission operators, transmission owners, generator operators, generator owners, distribution providers and regional reliability organizations and cover a wide range of topics related to the protection and control of power systems.

a. System Protection Coordination (PRC–001–1)

1420. PRC–001–1 [378] ensures that protection systems are coordinated among operating entities by requiring transmission and generator operators to notify appropriate entities of relay or equipment failures that could affect system reliability. In addition, transmission and generator operators must coordinate with appropriate entities when new protection systems are installed, or when existing protection systems are modified.

1421. In the NOPR, the Commission proposed to approve PRC–001–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit modifications to PRC–001–0 (proposed directives) that included: (1) Measures and Levels of Non-Compliance; (2) a requirement that transmission and generator operators be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities could carry out appropriate corrective control actions consistent with those used in mitigating IROL violations and (3) clarifying that, after being informed of failures in relays or protection system elements on the Bulk-Power System, transmission operators or generator operators carry out corrective control actions that return a system to a stable state as soon as possible, but no longer than 30 minutes after receiving a notice of failure.

i. Comments

1422. While Constellation supports the Commission's proposed directives because they represent additional steps to achieving reliability of the Bulk-Power System and eliminating undue discrimination, MISO questions the need for the Commission's proposals. MISO notes that virtually all protection schemes have backups. MISO asks whether the Commission wants facilities to be removed from service if one of the redundant relaying packages has a problem, or whether some other action should be taken besides such removal.

1423. With regard to the NOPR's direction to the ERO to include Measures and Levels of Non-Compliance, APPA states that the new Measures only partially address the Requirements, and in some cases, reference non-existent Requirements. For example, rather than referencing Requirement R5.1, new Measure M1 incorrectly refers to non-existent Requirement R8.1. Similarly, rather than referencing Requirement R5.2, new Measure M2 incorrectly refers to non-existent Requirement R8.2.

1424. APPA states that while it agrees that PRC–001–1 is sufficient for approval, since the new Measures only partially address the Requirements, and in some cases refer to non-existent Requirements, no penalties should be levied for violations of Requirements that have no accompanying Measures.

1425. WIRAB states that the Requirements, Measures and Levels of Non-Compliance do not provide guidance for the length of time—currently stated as ''as soon as possible''—permitted for corrective actions.

1426. APPA disagrees with the Commission's second and third directives to NERC. APPA states that the BAL and IRO Reliability Standards already have specific standards to notify affected entities and provide directions for recovery time. APPA acknowledges that in the NOPR, we stated that ''the Reliability Standards on mitigating IROL violations are not specific enough and system operators or field protection and control personnel would not be alerted about failures of relays and protection systems on critical elements.'' APPA, however, states that: ''If this is the Commission's view, then it should instruct NERC to re-examine the interaction between these two sets of standards [IROL and SOL and proposed PRCs] on remand, and to develop the most efficient solution to this problem. The Commission should not itself undertake to resolve this problem by issuing directives for specific revisions to PRC–001–1, especially if the result might be to have local level personnel countermanding the instruction of RC personnel at a time when the system is unstable.'' APPA asserts that the Commission should modify its proposed directives to allow NERC, as technical expert, to address the problems in the Reliability Standard that the Commission has identified.

1427. Dynegy states that in many situations, depending on the particular relay or protection system failure, an operator may not be able to complete corrective control actions that return the system to a stable state within 30 minutes, including troubleshooting of relays or restoring any tripped facilities. Dynegy find that a 30-minute time period may thus be overly rigid and punitive. Wisconsin Electric also requests further clarification of the 30-minute time limit to carry out corrective actions after a relay failure. It has additional concerns about older relays (*e.g.*, electromechanical relays) since it is impossible to know when and whether these older relays have failed. Wisconsin Electric also states that the NOPR is not clear about which relays threaten reliable system operation.

1428. Northern Indiana states that the NOPR appears to require immediate corrective actions whenever failures on relays or protection systems are detected, without regard to whether the specific failure detected reduces system reliability. It seeks the Commission's clarification that we do not intend to question a certified transmission operator's expertise in assessing whether a particular relay or protection system failure reduces system reliability.

1429. California PUC contends that imposing a time restriction for returning a system to a stable state may cause more harm than good since additional information and options may be available as time elapses. It repeats its suggestion from its earlier comments on

[378] In its November 15, 2006, filing, NERC submitted PRC–001–1, which supercedes the Version 0 Reliability Standard. PRC–001–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, PRC–001–1.

the Staff Preliminary Assessment and proposes the following alternative language: ''Transmission or generation operators shall carry out corrective control actions, *i.e.*, returning the system to a stable state that respects system requirements as soon as possible, and no longer than 30 minutes, except where a longer response time is feasible, or where a longer response is demonstrated to produce a better ultimate solution without unacceptable interim risk.''

1430. A number of commenters raise concerns that the proposal would be unnecessarily burdensome on generator operators. For example, Progress Electricity Committee asserts that the Commission's proposal to require generator operators to return the system to a stable state as soon as possible and within no longer than 30 minutes may be too burdensome for non-energy company users with on-site generation. California Cogeneration asserts that PRC–001–1 as a whole may impose unreasonable burdens on generators with no material impact on the grid, because most such generators will have no knowledge of the protection systems on the grid.

1431. Allegheny states that since generator operators do not have the same resources as transmission operators for taking corrective actions, the Commission's third proposed directive should be modified to apply only to transmission operators. Allegheny states that while a transmission operator can direct a generator operator to take specific actions, the reverse is not the case.

1432. FirstEnergy contends that Requirement R2.1 essentially requires generator operators to report all protective relay or equipment failures, since generator operators may not be able to tell which failures will reduce system reliability. FirstEnergy suggests that R2.1 should be revised to require generator operators to report all equipment failures or outages. FirstEnergy further suggests that PRC–001–1 be revised to provide that if a company performs reasonable testing procedures, undiscoverable equipment failures will not be violations of R2.1.

1433. MidAmerican states that the term ''immediately'' in the Commission's second directive is ambiguous and unenforceable. It suggests a 30-minute time limit.

ii. Commission Determination

1434. The Commission approves PRC–001–1 as mandatory and enforceable. We also direct NERC to develop a modification to PRC–001–1 through the Reliability Standards development process, as discussed below.

1435. The Commission observes that, collectively, the comments raise three general questions: (1) Whether relay or equipment failures reduce system reliability and, if so, in what circumstances; (2) what are ''corrective actions'' required to return a system to a secure operating state and (3) when is returning a system to a secure operating state ''as soon as possible.'' [379] The Commission will discuss each question in turn.

(a) Whether Relay or Equipment Failures Reduce System Reliability and, if So, in What Circumstances?

1436. Protection systems on Bulk-Power System elements are an integral part of reliable operations. They are designed to detect and isolate faulty elements on a power system, thereby limiting the severity and spread of disturbances and preventing possible damage to protected elements. If a protection system can no longer perform as designed because of a failure of its relays, system reliability is reduced or threatened. In deriving SOLs and IROLs, moreover, the functions, settings, and limitations of protection systems are recognized and integrated. Systems are only reliable when protection systems perform as designed. This is what PRC–001–1 means in linking a reduction in system reliability with a protection relay failure or other equipment failure.

1437. With respect to MISO's comment that virtually all protection systems have backups and therefore the Commission's proposals are not necessary, unless the backup protection has the same design goals and capabilities as the primary protection, a relay failure in the primary protection may still threaten system reliability. Further, we note that while the PRC Reliability Standards do not specifically require protection systems consisting of redundant and independent protection groups for each critical element in the Bulk-Power System, such requirements are included as one potential solution in the TPL Reliability Standards.[380]

1438. Finally, MISO's question seems to imply that if there are redundant relaying packages providing redundant protection, and a problem develops with only one of those redundant packages, system reliability is not threatened, and therefore, there is no need to take corrective control actions within 30 minutes. We agree with MISO's conclusion for this scenario.

1439. In the case, however, of a system element protected by a single protection system with a failed relay that threatens system reliability, that scenario would require the use of appropriate operating solutions including removing a system element from service. Another possible solution is to operate a system at a lower SOL or IROL that recognizes the degraded protection performance.

(b) What Are Corrective Actions?

1440. Corrective actions taken by transmission operators to return a system to a secure operating state when a protective relay or equipment failure reduces system reliability normally refer to ''operator control actions'', consisting of operator actions such as removing the facility without protection from service, generation redispatch, transmission re-configuration, etc. Corrective action must be completed as soon as possible, but no longer than 30 minutes after a notice of protection system failure. Failure to complete corrective action within 30 minutes will be considered a violation of the relevant IROL or TOP Reliability Standards. In contrast, troubleshooting or replacing failed relays or equipment are performed by field maintenance personnel and normally take hours or even days to complete. These actions are not normally considered corrective actions in the context of real-time operation of the Bulk-Power System.

1441. We believe that ''[t]he transmission operator shall take corrective action as soon as possible'' refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System.

1442. Dynegy, Wisconsin Electric and Northern Indiana are concerned that the time required to troubleshoot, repair or replace failed relays and equipment would be substantially longer than the 30 minutes set forth in the Commission's proposed directive. We believe we have alleviated this concern in our discussion, above. In addition, in response to Northern Indiana, we clarify that the responsibility for assessing whether a particular relay or protective system failure reduces system reliability remains with transmission operators. We direct the ERO to clarify the term

[379] PRC–001–1 Requirement R2.2 provides: ''If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.''

[380] If delayed clearing results in reliability criteria violations, one solution can be the use of redundant relay systems. TPL–002–0 Table 1, footnote e.

''corrective action'' consistent with this discussion when it modifies PRC–001–1 in the Reliability Standards development process.

1443. We agree with Allegheny that generator operators do not have the same ability as transmission operators to take corrective control actions on the Bulk-Power System, and we will modify our third directive as set forth below. We believe this also addresses Progress Electricity Committee and California Cogeneration's similar concerns.

(c) When Is ''As Soon as Possible''?

1444. As explained above, the requirement for system operators to take corrective control action when protective relay or equipment failure reduces system reliability should be treated the same as the requirement for returning a system to a secure and reliable state after an IROL violation, *i.e.*, as soon as possible, but no longer than 30 minutes after a violation. A longer time limit would place an entity in violation of relevant IROL or TOP Reliability Standards.

1445. The Commission directs the ERO to consider FirstEnergy and California PUC's comments about the maximum time for corrective action in the ERO Reliability Standards development process.

1446. In response to MidAmerican's request that we clarify the term ''immediately'' in our proposed second directive, we direct the ERO, in the Reliability Standards development process, to determine the appropriate amount of time after the detection of relay failures, in which relevant transmission operators must be informed of such failures.

1447. We agree with APPA that the added Measures and Levels of Non-Compliance incorrectly reference non-existent requirements. We direct the ERO to revise the references accordingly.

1448. We disagree with APPA that BAL and IRO Reliability Standards already address matters contained in PRC–001–1, because BAL and IRO are not related to relay and equipment failures, which are specifically addressed in PRC–001–1.

1449. We disagree with APPA's assertion that ''the Reliability Standards on mitigating IROL violations are not specific enough and system operators or field protection and control personnel would not be alerted about failure of relays and protection systems on critical elements.'' The time allowed for mitigating actual IROL violations is very clear: as soon as possible and within 30 minutes. We clarify that our concern is not about ''field protection and control personnel not being alerted about failure of relays and protection systems on critical elements.'' Our focus, rather, is that upon detection of failure of relays and protection systems on critical elements, field personnel must report the failures promptly to the transmission operators so that corrective operator control actions can be taken as soon as possible and within 30 minutes. Finally, with respect to APPA's contention that our proposed directives would result in local-level personnel undermining or not following the instructions of reliability coordinator personnel at a time when the system is unstable, we do not understand how local level personnel, who have no operating control of a transmission operator's system or a reliability coordinator's system could do so.

1450. The Commission approves Reliability Standard PRC–001–1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to PRC–001–1 through the Reliability Standards development process that: (1) Correct the references for Requirements and (2) include a requirement that upon the detection of failures in relays or protection system elements on the Bulk-Power System that threaten reliable operation, relevant transmission operators must be informed promptly, but within a specified period of time that is developed in the Reliability Standards development process, whereas generator operators must also promptly inform their transmission operators and (3) clarifies that, after being informed of failures in relays or protection system elements that threaten reliability of the Bulk-Power System, transmission operators must carry out corrective control actions, *i.e.*, return a system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes after they receive notice of the failure.

b. Define Regional Disturbance Monitoring and Reporting Requirements (PRC–002–1)

1451. PRC–002–1 ensures that each regional reliability organization establishes requirements to install Disturbance Monitoring Equipment (DME) and report disturbance data to facilitate analyses of events and verify system models.

1452. In the NOPR, the Commission identified PRC–002–1 as a fill-in-the-blank standard. The NOPR stated that because the regional requirements for installing DME had not been submitted, the Commission would not approve or remand PRC–002–1 until the ERO submitted the additional information.

i. Comments

1453. APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in addressing the completion of this Reliability Standard.

1454. Alcoa suggests that the ERO—instead of a Regional Entity—should define the requirements for DME and the type of report it generates. The requirements and equipment specifications should be consistent throughout North America. In addition, Alcoa suggests that the criteria for installation of such equipment should include the necessary monitoring and recording that contribute to analysis and enhance reliability.

1455. Otter Tail suggests that PRC–002–1 should be developed on an Interconnection-wide basis to ensure consistency and promote reliability of the Bulk-Power System.

ii. Commission Determination

1456. For the reasons stated in the NOPR, the Commission will not approve or remand PRC–002–1.

1457. We agree with APPA, Alcoa and Otter Tail that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No. 672, the Commission also encouraged greater uniformity in the development of Reliability Standards.[381] Consistent with that goal, the Commission directs the ERO to consider APPA, Alcoa and Otter Tail's suggestions in the Reliability Standards development process as it modifies PRC–002–1 to provide missing information needed for the Commission to act on this Reliability Standard.

c. Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems (PRC–003–1)

1458. PRC–003–1 ensures that all transmission and generation protection system misoperations are analyzed, and corrective action plans are developed. Misoperations occur when a protection system operates when it should not or does not operate when it should. This Reliability Standard requires each regional reliability organization to develop a procedure to monitor and review misoperations of protection

[381] Order No. 672 at P 292.

systems and to develop and document corrective actions.

1459. In the NOPR, the Commission identified PRC–003–1 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC–003–1 until the ERO submitted the additional information.

i. Comments

1460. APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids and industry structures. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in completing this Reliability Standard.

ii. Commission Determination

1461. For the reasons stated in the NOPR, the Commission will not approve or remand PRC–003–1.

1462. We agree with APPA that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No. 672, the Commission also encouraged greater uniformity in the development of Reliability Standards.[382] Consistent with that goal, the Commission directs the ERO to consider APPA's suggestions in the Reliability Standards development process as it modifies PRC–003–1 to provide missing information needed for the Commission to act on this Reliability Standard.

d. Analysis and Reporting of Transmission Protection System Misoperations (PRC–004–1)

1463. PRC–004–1 ensures that all transmission and generation protection system misoperations affecting the reliability of the Bulk-Power System are analyzed and mitigated by requiring transmission owners, generator owners and distribution providers that own a transmission protection system to analyze and document protection system misoperations. These entities must also develop corrective action plans in accordance with the regional reliability organization's procedures.

1464. In the NOPR, the Commission proposed to approve PRC–004–1 as mandatory and enforceable.

i. Comments

1465. APPA agrees that PRC–004–1 is sufficient for approval as a mandatory and enforceable Reliability Standard.

1466. ISO–NE and ISO/RTO Council oppose the Commission's proposed approval of PRC–004–1 because it relies on PRC–003–1, a fill-in-the-blank standard, which the Commission does not propose to approve or remand until the ERO submits additional information.

1467. ISO–NE further requests the Commission to direct NERC to modify PRC–004–1 to include LSEs and transmission operators in the applicability section. It states that based on current practice in the ISO–NE balancing area, transmission operators, transmission owners, LSEs and distribution providers may individually or jointly own and operate a protection system. It therefore suggests that transmission operators and LSEs should also be included in the applicability section. ISO–NE provides the same suggestion with regard to PRC–005–1, PRC–008–0, PRC–011–0, PRC–015–0, PRC–016–0, PRC–017–0 and PRC–021–1.

ii. Commission Determination

1468. The Commission approves Reliability Standard PRC–004–1 as mandatory and enforceable.

1469. We are not persuaded by ISO–NE and ISO/RTO Council's assertion that PRC–004–1 should not be approved because it refers to PRC–003–1, which is a fill-in-the-blank standard. In part, we neither approve nor remand PRC–003–1 because it applies to a regional reliability organization, and we are not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as NERC proposes.[383] This is not the case with PRC–004–1, which applies to transmission owners, distribution providers, and generator owners. Since PRC–004–1 is an existing Reliability Standard that has been followed on a voluntary basis, transmission owners, distribution providers and generator owners are on notice of requirements related to misoperations of transmission and generation protection systems. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard.

1470. We direct the ERO to consider ISO–NE's suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC–004–1.[384] Further, as the ERO reviews this Reliability Standard in its five-year cycle of review, the Regional Entity, rather the regional reliability organization, should develop the procedures for corrective action plans.

e. Transmission and Generation Protection System Maintenance and Testing (PRC–005–1)

1471. PRC–005–1 ensures that all transmission and generation protection systems affecting the reliability of the Bulk-Power System are maintained and tested by requiring the transmission owners, distribution providers, and generator owners to develop, document, and implement a protection system maintenance program that may be reviewed by the regional reliability organization.

1472. In the NOPR, the Commission proposed to approve PRC–005–1 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC–005–1 that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System.

i. Comments

1473. FirstEnergy states that NERC should establish a maximum maintenance interval for protection system equipment, and a national limitation taking into account both relay type and functional versus calibration testing. Entergy does not object to the development of maximum allowable maintenance intervals provided that they are developed in NERC's Reliability Standards development process.

1474. FirstEnergy and ISO–NE suggest that PRC–005–1, PRC–008–0, PRC–011–0 and PRC–017–0 should be combined into a single Reliability Standard relating to the maintenance of protection and control equipment.

ii. Commission Determination

1475. For the reasons stated in the NOPR, the Commission approves Reliability Standard PRC–005–1 as mandatory and enforceable.

1476. In addition, for the reasons discussed in the NOPR, the Commission directs the ERO to develop a modification to PRC–005–1 through the

[382] *Id.* at P 292.

[383] NOPR at P 56–57.

[384] The same suggestion and therefore same Commission response also applies to PRC–005–1, PRC–008–0, PRC–011–0, PRC–015–0, PRC–016–0, PRC–017–0 and PRC–021–1.

Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System. We further direct the ERO to consider FirstEnergy's and ISO–NE's suggestion to combine PRC–005–1, PRC–008–0, PRC–011–0 and PRC–017–0 into a single Reliability Standard through the Reliability Standards development process.

f. Development and Documentation of Regional UFLS Programs (PRC–006–0)

1477. PRC–006–0 ensures the development of a regional UFLS [385] program that will be used as a last resort to preserve the Bulk-Power System during a major system failure that could cause system frequency to collapse. PRC–006–0 requires the regional reliability organization to develop, coordinate, document and assess UFLS program design and effectiveness at least every five years.

1478. In the NOPR, the Commission identified PRC–006–0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand PRC–006–0 until the ERO submits the additional information. The Commission commends the ERO and regions' initiative, outlined in the Reliability Standards Work Plan, in adopting an integrated and coordinated approach to protection for generators, transmission lines and UFLS and UVLS [386] programs as part of its work on fill-in-the-blank Reliability Standards.[387]

i. Comments

1479. APPA agrees with the Commission's proposed course of action. It suggests that in completing this Reliability Standard, NERC should strive for greater consistency on an Interconnection-wide basis through the use of ''base procedures'' for each Interconnection.

ii. Commission Determination

1480. For the reasons stated in the NOPR, the Commission will not approve or remand PRC–006–0.

1481. The Commission understands that UFLS, when properly coordinated with the dynamic response of the Bulk-Power System, is one of the safety nets that safeguards the system from cascading events, assuming it is properly coordinated with the dynamic response of the system. Until this Reliability Standard is submitted to the Commission for approval, we do not expect any lapse in the compliance with this Reliability Standard. As we stated in the NOPR, it is important that the existing regional reliability organizations continue to fulfill their current roles during this time of transition. The Commission expects that this function will pass from the regional reliability organization to the Regional Entity after they are approved.

g. Assuring Consistency With Regional UFLS Program Requirements (PRC–007–0)

1482. PRC–007–0 requires transmission owners, transmission operators, LSEs and distribution providers to provide, and annually update, their underfrequency data to facilitate the regional reliability organization's maintenance of the UFLS program database.

1483. In the NOPR, the Commission proposed to approve PRC–007–0 as mandatory and enforceable.

i. Comments

1484. APPA agrees that PRC–007–0 is sufficient for approval as a mandatory and enforceable Reliability Standard. However, it states that actual enforcement cannot take place until PRC–006–0 becomes effective. ISO–NE and ISO/RTO Council state that PRC–007–0 should not be approved because it refers to PRC–006–0, which we are not approving or remanding at this time.

ii. Commission Determination

1485. For the reasons stated in the NOPR, the Commission approves Reliability Standard PRC–007–0 as mandatory and enforceable.

1486. We are not persuaded by APPA, ISO/RTO Council and ISO–NE that PRC–007–0 cannot be acted on because it relies on PRC–006–0. We proposed to not approve or remand PRC–006–0 partly because it applies to a regional reliability organization. The Commission was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as NERC proposed.[388] That is not the case with PRC–007–0, which applies to transmission owners, transmission operators, distribution providers and LSEs. Since PRC–007–0 is an existing Reliability Standard that has been followed on a voluntary basis, transmission owners, transmission operators, distribution providers and LSEs are generally aware of its requirements. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects that the data will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

h. Underfrequency Load Shedding Equipment Maintenance Programs (PRC–008–0)

1487. PRC–008–0 requires transmission owners and distribution providers to implement UFLS equipment maintenance and testing programs and provide program results to the regional reliability organization.

1488. In the NOPR, the Commission proposed to approve Reliability Standard PRC–008–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC–008–0 that includes a requirement that maintenance and testing of UFLS programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System.

i. Comments

1489. Entergy states that it does not object to NERC's development of maximum allowable maintenance intervals for the purpose of evaluating protection system and control programs provided that they are developed in NERC's Reliability Standards development process. FirstEnergy states that NERC should establish a maximum maintenance interval for protection system equipment and a ''national limitation taking into account both relay type and functional versus calibration testing.''

1490. ISO–NE and ISO/RTO Council contend that the Commission should not approve PRC–008–0 until it approves PRC–006–0, which the Commission has identified as a fill-in-the-blank standard. Similarly, APPA contends that PRC–008–0 cannot be enforced until PRC–006–0 has become effective and the required regional UFLS program documentation has been submitted by the applicable Regional Entity. It also notes that the applicability of PRC–008–0 is limited to transmission owners and distribution providers who are required by their regional reliability organization to have a UFLS program.

[385] Underfrequency load shedding.

[386] Undervoltage load shedding.

[387] NOPR at P 367.

[388] NOPR at P 56–57.

ii. Commission Determination

1491. FirstEnergy and Entergy agree with the Commission's proposed directive, whereas APPA suggests that the need for the proposal should be established first via the Reliability Standards development process.

1492. We disagree with ISO/RTO Council and others that approval or enforcement of PRC–008–0 is linked to approval of PRC–006–0. PRC–008–0 requires that a ''transmission provider or distribution provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment and maintenance testing program in place.'' [389] PRC–006–0 requires each regional reliability organization to develop, coordinate and document a UFLS program that includes specified elements. Again, we proposed to neither approve nor remand PRC–006–0 because it applies to a regional reliability organization and the Commission was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as proposed by NERC.[390] That is not the case with PRC–008–0, which applies to transmission owners and distribution providers. Since PRC–008–0 is an existing Reliability Standard that has been followed on a voluntary basis, transmission owners and distribution providers are aware whether they are required to have a UFLS program in place. We approve PRC–008–0 as mandatory and enforceable because it requires entities to have equipment maintenance and testing of their UFLS programs. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects that the program results will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

1493. The Commission approves Reliability Standard PRC–008–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to PRC–008–0 through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System.

i. UFLS Performance Following an Underfrequency Event (PRC–009–0)

1494. PRC–009–0 ensures that the performance of a UFLS system is analyzed and documented following an underfrequency event by requiring the transmission owner, transmission operator, LSE and distribution provider to document the deployment of their UFLS systems in accordance with the regional reliability organization's program.

1495. In the NOPR, the Commission proposed to approve Reliability Standard PRC–009–0 as mandatory and enforceable.

i. Comments

1496. APPA agrees that PRC–009–0 is sufficient for approval as a mandatory and enforceable Reliability Standard. However, it states that actual enforcement cannot take place until pending PRC–006–0 becomes effective and notes that the applicability of PRC–009–0 is limited to entities that own or operate a UFLS program recognized by their regional reliability organization.

1497. ISO–NE and ISO/RTO Council contend that the Commission should not approve PRC–009–0 until it approves PRC–006–0, which the Commission has identified as a fill-in-the-blank standard.

ii. Commission Determination

1498. For the reasons stated in the NOPR, the Commission approves Reliability Standard PRC–009–0 as mandatory and enforceable.[391]

1499. We disagree with ISO/RTO Council and others that approval or enforcement of PRC–009–0 is linked to approval of PRC–006–0. PRC–009–0 ensures that the performance of a UFLS system is analyzed and documented following an underfrequency event by requiring the transmission owner, transmission operator, LSE, and distribution provider to document the deployment of their UFLS operations. PRC–006–0 requires each regional reliability organization to develop, coordinate and document a UFLS program that includes specified elements. We proposed to neither approve nor remand PRC–006–0 because it applies to a regional reliability organization and the Commission was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as NERC proposed.[392] That is not the case with PRC–009–0, which applies to transmission owners, transmission operators, LSEs and distribution providers with UFLS systems. Since PRC–009–0 is an existing Reliability Standard that has been followed on a voluntary basis, entities are aware whether they are required to have a UFLS program in place. Reporting on their UFLS programs therefore should not be burdensome. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects this documentation will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

j. Assessment of the Design and Effectiveness of UVLS Program (PRC–010–0)

1500. PRC–010–0 requires transmission owners, transmission operators, LSEs and distribution providers to periodically conduct and document an assessment of the effectiveness of their UVLS program at least every five years or as required by changes in system conditions. The assessment must be conducted with the associated transmission planner and planning authority.

1501. In the NOPR, the Commission proposed to approve Reliability Standard PRC–010–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC–010–0 that requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride-through capabilities and UFLS and UVLS programs.

1502. The Commission commends the initiative and efforts that have been taken by NERC and the industry in addressing UVLS requirements as recommended by the Blackout Report.

i. Comments

1503. APPA agrees that PRC–010–0 should be approved. While APPA agrees and that NERC should re-examine this Reliability Standard to determine whether a more integrated and coordinated approach should be included in protection systems on the Bulk-Power System, it also asks the Commission not to require a specific approach to UVLS and other protection systems. According to APPA, NERC should strive for greater consistency on an Interconnection-wide basis through

[389] *See* PRC–008–0, Requirement R1.

[390] NOPR at P 56–57.

[391] NOPR at P 877–80.

[392] NOPR at P 56–57.

the use of a coordinated protection system for the Bulk-Power System in each Interconnection.

1504. ISO–NE generally supports approval of PRC–010–0, but opposes the Commission's directive to modify the Reliability Standard to include an integrated and coordinated approach in all protection systems, particularly for UVLS and UFLS, programs, because such integration cannot be technologically accomplished.

1505. FirstEnergy indicates that UVLS is primarily designed to address localized problems, and therefore requiring the universal coordination of UVLS across the grid does not make sense. FirstEnergy states that it is not clear what type of coordination would be useful for a UVLS program.

ii. Commission Determination

1506. We agree with APPA's comments and reiterate that the directed modification should be developed in the Reliability Standards development process. With regard to APPA's concerns, while we direct the ERO to develop modifications that would require an integrated and coordinated approach to protection systems, we do not direct a specific approach to accomplish such integration and coordination. Rather, the ERO should develop an appropriate approach utilizing the Reliability Standards development process.

1507. With regard to ISO–NE's disagreement on integration of various system protections ''because such integration cannot be technologically accomplished'', we note that the evidence collected in the Blackout Report indicates that ''the relay protection settings for the transmission lines, generators and underfrequency load shedding in the northeast may not be entirely appropriate and are certainly not coordinated and integrated to reduce the likelihood and consequence of a cascade—nor were they intended to do so.'' In addition, the Blackout Report stated that one of the common causes of major outages in North America is a lack of coordination on system protection. The Commission agrees with the protection experts who participated in the investigation, formulated Blackout Recommendation No. 21 and recommended that UVLS programs have an integrated approach.[393]

1508. Regarding FirstEnergy's question of whether universal coordination among UVLS programs that address local system problems makes sense, we believe that PRC–010–0's objective in requiring an integrated and coordinated approach is to address the possible adverse interactions of these protection systems among themselves and to determine whether they could aggravate or accelerate cascading events. We do not believe this Reliability Standard is aimed at universal coordination among UVLS programs that address local system problems.

1509. As identified in the NOPR,[394] NERC is continuing to develop an integrated and coordinated approach to protection for generators, transmission lines and UFLS and UVLS programs within its work on the fill-in-the-blank proposed Reliability Standards.

1510. We appreciate MEAG's feedback to our response in the NOPR. For the reasons discussed in the NOPR,[395] as well as our explanation above, the Commission approves Reliability Standard PRC–010–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to PRC–010–0 through the Reliability Standards development process that requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride-through capabilities, and UFLS and UVLS programs.

k. UVLS System Maintenance and Testing (PRC–011–0)

1511. PRC–011–0 requires transmission owners and distribution providers to implement their UVLS equipment maintenance and testing programs and provide program results to regional reliability organizations.

1512. In the NOPR, the Commission proposed to approve PRC–011–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC–011–0 that includes a requirement that maintenance and testing of UVLS programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System.

i. Comments

1513. APPA suggests that, instead of a Commission directive, NERC should be directed to consider whether this standard is needed to address the Commission's concern about periodic testing of UVLS equipment.

1514. FirstEnergy comments that NERC should establish a maximum maintenance interval for protection system equipment, and a ''national limitation taking into account both relay type and functional versus calibration testing.'' Entergy states that it does not object to NERC's development of maximum allowable maintenance intervals for the purpose of evaluating protection system and control programs.

ii. Commission Determination

1515. The Commission approves Reliability Standard PRC–011–0 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process as discussed below.

1516. The Commission disagrees with APPA that the decision whether a modification is needed should be established first by the ERO in its Reliability Standards development process. Our direction identifies an appropriate goal necessary to assure the reliable operation of the Bulk-Power System. The details should be developed through the Reliability Standards development process.

1517. The Commission believes that the proposal is presently part of the process. The Commission approves Reliability Standard PRC–011–0 as mandatory and enforceable. In addition, the Commission directs the ERO to submit a modification to PRC–011–0 through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System.

l. Special Protection System Review Procedure (PRC–012–0)

1518. PRC–012–0 requires regional reliability organizations to ensure that all special protection systems [396] are properly designed, meet performance requirements and are coordinated with other protection systems.

In the NOPR, the Commission identified PRC–012–0 as a fill-in-the-blank standard. The NOPR stated that

[393] ''Recommend that NERC determine the goal and principles needed to establish an integrated approach to relay protection for generators and transmission lines and the use of underfrequency and undervoltage load shedding programs.'' Blackout Report at 159.

[394] NOPR P 883.

[395] *Id.* P 891–92.

[396] A special protection system is designed to automatically take corrective actions to protect a particular system under both abnormal and predetermined conditions, excluding the coordinated tripping of circuit breakers to isolate faulted components, which is typically the purpose of other protection devices.

because the regional review procedures on special protection systems have not been submitted, the Commission would not propose to approve or remand PRC–012–0 until the ERO submits the additional information.

i. Comments

1520. APPA agrees with the Commission's proposed course of action. It further suggests that NERC, in completing PRC–012–0, should strive for greater consistency on an Interconnection-wide basis through the use of ''base procedures'' for each Interconnection.

ii. Commission Determination

1521. For the reasons stated in the NOPR, the Commission will not approve or remand PRC–012–0. The Commission urges the ERO should consider APPA's suggestions in the Reliability Standards development process.

m. Special Protection System Database (PRC–013–0)

1522. PRC–013–0 ensures that all special protection systems are properly designed, meet performance requirements and are coordinated with other protection systems by requiring the regional reliability organization to maintain a database of information on special protection systems.

1523. In the NOPR, the Commission identified PRC–013–0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures on maintaining special protection system databases have not been submitted, the Commission would not approve or remand PRC–013–0 until the ERO submits the additional information.

i. Comments

1524. APPA agrees with the Commission's proposed course of action. It suggests further that in completing PRC–013–0, NERC should strive for greater consistency on an Interconnection-wide basis through the use of ''base procedures'' for each Interconnection.

ii. Commission Determination

1525. For the reasons stated in the NOPR, the Commission will not approve or remand PRC–013–0. The ERO should consider APPA's suggestions in the Reliability Standards development process.

n. Special Protection System Assessment (PRC–014–0)

1526. PRC–014–0 ensures that special protection systems are properly designed, meet performance requirements and are coordinated with other protection systems by requiring the regional reliability organization to assess and document the operation, coordination and compliance with NERC Reliability Standards and effectiveness of special protection systems at least once every five years.

1527. In the NOPR, the Commission identified PRC–014–0 as a fill-in-the-blank Reliability Standard. The NOPR stated that because the regional procedures on special protection system assessment had not been submitted, the Commission would not propose to approve or remand PRC–014–0 until the ERO submitted the additional information.

i. Comments

1528. APPA agrees with the Commission's proposed course of action. It suggests further that in completing PRC–014–0, NERC should strive for greater consistency on an Interconnection-wide basis through the use of ''base procedures'' for each Interconnection.

ii. Commission Determination

1529. For the reasons stated in the NOPR, the Commission will not approve or remand PRC–014–0. The ERO should consider APPA's suggestions in the Reliability Standards development process.

o. Special Protection System Data and Documentation (PRC–015–0)

1530. Proposed Reliability Standard PRC–015–0 requires transmission owners, generator owners and distribution providers to maintain a listing, retain evidence of review and provide documentation of existing, new or functionally modified special protection systems.

1531. In the NOPR, the Commission proposed to approve PRC–015–0 as mandatory and enforceable.

i. Comments

1532. APPA agrees that PRC–015–0 is sufficient for approval as a mandatory Reliability Standard. However, it states that this Reliability Standard cannot be enforced until two pending Reliability Standards, PRC–012–0 and PRC–013–0, become effective. Similarly, ISO/RTO Council and ISO–NE contend that the Commission should not approve PRC–15–0 until it approves PRC–012–0 and PRC–013–0, identified by the Commission as fill-in-the-blank standards.

ii. Commission Determination

1533. We disagree with APPA, ISO/RTO Council and ISO–NE and conclude that PRC–015–0 should be approved and made enforceable on the effective date of this rulemaking. As mentioned above, PRC–012–0 and PRC–013–0 apply solely to regional reliability organizations. PRC–012 is ''process'' oriented, as it requires the regional reliability organization to develop a review procedure that identifies information relevant to the regional reliability organization review of a special protection system. PRC–013–0 requires the regional reliability organization to maintain a database of information on special protection systems. PRC–015–0 requires a transmission owner, generator owner or distribution provider that owns a special protection system to maintain a list and provide data for existing and planned special protection systems as defined in PRC–013–0; and have evidence that the entity reviewed new or functionally modified special protection systems in accordance with the regional reliability organization procedures identified in PRC–012–0. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects that the data will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

1534. For the reasons discussed in the NOPR and above, the Commission concludes that Reliability Standard PRC–015–0 is just, reasonable, not unduly discriminatory or preferential and in the public interest and approves it as mandatory and enforceable.

p. Special Protection System Misoperations (PRC–016–0)

1535. PRC–016–0 requires transmission owners, generator owners and distribution providers to provide the regional reliability organization with documentation, analyses and corrective action plans for misoperation of special protection systems.

1536. In the NOPR, the Commission proposed to approve Reliability Standard PRC–016–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC–016–0 that includes a requirement that maintenance and testing of these special protection system programs be carried out within a maximum allowable interval that is appropriate for the type of relays used and the impact of these special system protection systems on the reliability of the Bulk-Power System.

i. Comments

1537. While APPA agrees that PRC–016–0 is sufficient for approval as a mandatory Reliability Standard, APPA, ISO/RTO Council and ISO–NE state that PRC–016–0 cannot be enforced until pending Reliability Standard PRC–012–0 has become effective.

1538. FirstEnergy suggests that NERC clarify and provide guidance to transmission operators on the types of misoperations that have Interconnection-wide impacts and the types of misoperations that need reporting.

ii. Commission Determination

1539. PRC–016–0 states that transmission owners, generator owners and distribution providers that own a special protection system must analyze the system operations and maintain a record of misoperations in accordance with the review procedure specified in PRC–012–0. As we explained above in the context of PRC–015–0, applicable entities are expected to comply with PRC–015–0, and the procedures specified in PRC–012–0 will continue to be maintained by the regional reliability organizations pursuant to the ERO Rules of Procedure and the Commission's reliability information provision. We disagree with APPA, ISO/RTO Council and ISO–NE and conclude that PRC–016–0 is enforceable as of the effective date of this rulemaking. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects that the plans will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

1540. The Commission concludes that Reliability Standard PRC–016–0 is just, reasonable, not unduly discriminatory or preferential, and in the public interest, and approves it as mandatory and enforceable. We observe that a maximum allowable interval for maintenance and testing of special protection systems is not relevant to PRC–016–0, where the primary purpose is to analyze and report all misoperations of special protection systems. The Commission, therefore, will not adopt the proposal to require the ERO to modify PRC–016–0 to include a requirement for a maximum allowable interval for maintenance and testing.

1541. The Commission concludes that Reliability Standard PRC–016–0 is just, reasonable, not unduly discriminatory or preferential and in the public interest, and approves it as mandatory and enforceable.

q. Special Protection System Maintenance and Testing (PRC–017–0)

1542. PRC–017–0 requires transmission owners, generator owners and distribution providers to provide the regional reliability organization with documentation of special protection system maintenance, testing and implementation plans.

1543. In the NOPR, the Commission proposed to approve PRC–017–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC–017–0 that: (1) Includes a requirement that maintenance and testing of these special protection system programs must be carried out within a maximum allowable interval that is appropriate to the type of relaying used and (2) identifies the impact of these special protection system programs on the reliability of the Bulk-Power System.

i. Comments

1544. APPA agrees that PRC–017–0 is sufficient for approval as a mandatory and enforceable Reliability Standard. It also agrees that NERC and the industry should consider adoption of maximum allowable maintenance intervals. With respect to the Commission's second directive, APPA points out that the documentation of the test results will identify the impact of the special protection systems on the Bulk Electric System.

1545. FirstEnergy states that NERC should establish a maximum maintenance interval for protective system equipment and a national limitation, taking into account both relay type and functional versus calibration testing. Entergy does not object to NERC's development of maximum allowable maintenance intervals for the purpose of evaluating protection system and control programs.

ii. Commission Determination

1546. The commenters agree with the Commission's proposed directive on a maximum allowable interval for maintenance and testing of protection system equipment and we conclude that such a modification is beneficial. However, we agree with APPA's view on our second proposed directive assuming that the documentation is requested by either the regional reliability organization or NERC. Therefore, we will modify our direction to require that the documentation be routinely provided to the ERO or Regional Entity and not only when it is requested.

1547. The Commission approves Reliability Standard PRC–017–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to PRC–017–0 through the Reliability Standards development process, that includes: (1) a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate for the type of the protection system and (2) a requirement that documentation identified in Requirement R2 shall be routinely provided to the ERO or Regional Entity.

r. Disturbance Monitoring Equipment Installation and Data Reporting (PRC–018–1)

1548. PRC–018–1 ensures that disturbance monitoring equipment is installed and disturbance data is reported in accordance with comprehensive requirements. PRC–018–1 contains several different effective dates for specific requirements.

1549. In the NOPR, the Commission proposed to approve PRC–018–1 as mandatory and enforceable.

i. Comments

1550. While APPA agrees that PRC–018–1 is sufficient for approval as a mandatory Reliability Standard, it contends that enforcement is not possible until PRC–002–0, a fill-in-the-blank standard, is effective. For the same reason, ISO/RTO Council and ISO–NE state that the Reliability Standard should not be approved or remanded at this time.

ii. Commission Determination

1551. The portion of PRC–018–1 that NERC proposes will become effective on the effective date of this Final Rule states that transmission owners and generator owners that own a disturbance monitoring system must assure that disturbance data is reported in accordance with PRC–002–1 to facilitate analyses of events. Applicable entities are expected to comply with PRC–018–1, and the procedures specified in PRC–002–1 will be provided pursuant to the data gathering provisions of the ERO's Rules of Procedure and the Commission's ability to obtain information pursuant to section 215 of the FPA and Part 39 of the Commission's regulations. Accordingly, we disagree with ISO/RTO Council and ISO–NE and conclude that the effective portions of PRC–018–1 are enforceable as of the effective date of this rulemaking. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be

considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard.

1552. Accordingly, for reasons stated in the NOPR and above, the Commission approves Reliability Standard PRC–018–1 as mandatory and enforceable.

s. Undervoltage Load Shedding Program Database (PRC–020–1)

1553. PRC–020–1 ensures that a regional database for UVLS programs is available for Bulk-Power System studies by requiring regional reliability organizations with any entities that have UVLS programs to maintain and annually update a database.

1554. In the NOPR, the Commission identified PRC–020–1 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures on maintaining UVLS databases have not been submitted, the Commission would not propose to approve or remand PRC–020–0 until the ERO submits the additional information.

i. Comments

1555. APPA disagrees that PRC–020–1 is a regional fill-in-the-blank Reliability Standard because it does not require regional procedures. However, APPA recognizes that PRC–020–1 requires the regional reliability organization to establish a database.

ii. Commission Determination

1556. APPA is correct that the reason for not approving or remanding this Reliability Standard is because it applies solely to the regional reliability organization, and not because it is a fill-in-the-blank standard. For this reason, the Commission will not approve or remand PRC–020–1.

t. Undervoltage Load Shedding Program Data (PRC–021–1)

1557. PRC–021–1 ensures that data is supplied to support the regional UVLS database by requiring the transmission owner and distribution provider to supply data related to their systems and other related protection schemes to their regional reliability organization's database.

1558. In the NOPR, the Commission proposed to approve PRC–021–1 as mandatory and enforceable.

i. Comments

1559. APPA agrees that PRC–021–1 should be approved as a mandatory and enforceable Reliability Standard.

1560. The ISO–NE and ISO/RTO Council contend that the Commission should refrain from approving PRC–021–1 until it approves PRC–020–1 which the Commission has not approved or remanded.

ii. Commission Determination

1561. For the reasons stated in the NOPR and above, the Commission approves PRC–021–1 as mandatory and enforceable. The referenced information will be provided pursuant to the data gathering provisions of the ERO's rules of procedure and the Commission's ability to obtain information pursuant to section 215 of the FPA and Part 39 of the Commission's regulations. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard.

u. Undervoltage Load Shedding Program Performance (PRC–022–1)

1562. PRC–022–1 requires transmission operators, LSEs, and distribution providers to provide analysis, documentation and misoperation data on UVLS operations to the regional reliability organization.

1563. In the NOPR, the Commission proposed to approve PRC–022–1 as mandatory and enforceable.

i. Comments

1564. APPA agrees that PRC–022–1 should be approved as a mandatory and enforceable Reliability Standard.

1565. FirstEnergy comments that Requirement R1.3 requires ''a simulation of the event, if deemed appropriate by the RRO'' and believes that the applicable entities such as transmission operators may not be able to simulate large system events. FirstEnergy suggests that Requirement R1.3 be revised to state that ''a simulation of the event, if deemed appropriate, and assisted by the [regional reliability organization].''

ii. Commission Determination

1566. For the reasons discussed in the NOPR, the Commission concludes that Reliability Standard PRC–022–1 is just, reasonable, not unduly discriminatory or preferential, and in the public interest and approves it as mandatory and enforceable.

1567. The Commission directs the ERO to consider FirstEnergy's suggestion in the Reliability Standards development process.

11. TOP: Transmission Operations

1568. The eight Transmission Operations (TOP) Reliability Standards apply to transmission operators, generator operators and balancing authorities. The goal of these Reliability Standards is to ensure that the transmission system is operated within operating limits. Specifically, these Reliability Standards cover the responsibilities and decision-making authority for reliable operations, requirements for operations planning, planned outage coordination, real-time operations, provision of operating data, monitoring of system conditions, reporting of operating limit violations and actions to mitigate such violations. The Interconnection Reliability Operations and Coordination (IRO) group of Reliability Standards complement these proposed TOP Reliability Standards.

a. Reliability Responsibilities and Authorities (TOP–001–1)

1569. The reliability goal of TOP–001–1 is to ensure that system operators have the authority to take actions and direct others to take action to maintain Bulk-Power System facilities within operating limits. TOP–001–1 requires that: (a) Transmission operating personnel must have the authority to direct actions in real-time; (b) the transmission operator, balancing authority, and generator operator must follow the directives of their reliability coordinator and (c) the balancing authority and generator operator must follow the directives of the transmission operator. In addition, the proposed Reliability Standard requires the transmission operator, balancing authority, generator operator, distribution provider and LSE to take emergency actions when directed to do so in order to keep the transmission system intact.

1570. The Commission proposed in the NOPR to approve the Reliability Standard as mandatory and enforceable and to direct NERC to submit a modification to it that includes Measures and Levels of Non-Compliance. On November 15, 2006, NERC submitted revisions to the Reliability Standard to include Measures and Levels of Non-Compliance.[397]

i. Comments

1571. APPA notes that TOP–001–1, as revised to include Measures and Levels of Non-Compliance, fulfills the proposed directive in the NOPR. Accordingly, APPA agrees that the Commission should approve TOP–001–1 as mandatory and enforceable.

[397] In its November 15, 2006, filing, NERC submitted TOP–001–1, which supercedes the Version 0 Reliability Standard. TOP–001–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, TOP–001–1.

1572. California PUC asserts that TOP–001 should not be adopted unless the Commission provides for proper deference to existing authorities. It states that the requirements contained in TOP–001 are duplicative of what the CAISO already requires under its participating generator agreements.

1573. FirstEnergy contends that TOP–001–1 contains ''reliability directives'' to be followed by various entities, but it has no clear line of authority for specified directives. This could lead to a generator receiving conflicting directions. FirstEnergy maintains that TOP–001–1 should establish a clear line of authority for issuing and complying with directives, but the reliability coordinator's instructions should govern in all instances.

1574. In a similar vein, MEAG Power is concerned that the scope of ''reliability directives'' contained in the Measures filed on November 15, 2006 is unclear. For example, Measure M4 states that ''[e]ach Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence that * * * it complied with its Transmission Operator's reliability directives.'' While a directive by a transmission operator to a LSE to increase its planning reserve margin from 15 percent to 20 percent or reconductor a transmission line might be within the realm of possibilities, such ''reliability directives'' would be inappropriate. MEAG Power therefore recommends an alternative definition of ''reliability directive'' that it believes would specify an appropriate range of directives.

1575. MEAG Power also recommends a modification to TOP–001–1 clarifying that an entity may be found non-compliant only if it fails to comply with a reliability directive issued to it by its host reliability coordinator. MEAG Power is concerned that the requirements as currently written may apply to entities outside a reliability coordinator's footprint.

1576. FirstEnergy and California Cogeneration state that the definition of ''emergency'' is vague and should be clarified. FirstEnergy states TOP–001 does not specify who decides when there is an emergency. California Cogeneration states that under emergency conditions, it would be appropriate to require a QF to follow the directives of a reliability coordinator.[398] But California Cogeneration argues that because of the broad definition of emergency, reliability coordinators could issue directives on a regular basis. California Cogeneration therefore proposes that the Reliability Standard clearly address which entities are exempt from such directives because they have no material impact on reliability.

1577. FirstEnergy states that the term ''safety'' in Requirement R4 should be clarified with respect to whether it means safety to the system/equipment, public safety or both.

1578. Requirement R6 of TOP–001–1 requires an applicable entity to ''render all available emergency assistance to others as requested.'' Regarding this provision, FirstEnergy maintains that NERC should clarify that all instructions should be subject to the reliability coordinator's direction and control to avoid causing unforeseen harm to other systems. Any entity requesting assistance must implement its emergency procedures before or in unison with assistance from other entities. However, FirstEnergy asserts that it is not clear how a responding entity will determine whether the requesting entity has implemented its comparable emergency procedures before the responding entity honors the request. FirstEnergy, therefore, states that TOP–001–1 should require the requesting party to report on whether all of its emergency procedures were implemented as part of its request for emergency assistance.

1579. Santa Clara states that, in some instances, notifying the reliability coordinator that a transmission operator is removing facilities from service may not be appropriate because the transmission owner traditionally notifies the balancing authority. Santa Clara therefore requests that Requirements R7.2 and R7.3 of the Reliability Standard be revised to provide that the transmission operator may notify the reliability coordinator or balancing authority.[399]

ii. Commission Determination

1580. The Commission approves TOP–001–1 as mandatory and enforceable. We address the concerns raised by commenters below.

1581. While the Commission agrees with APPA that TOP–001–1 should be approved, it does not agree that the new Measures and Levels of Non-Compliance fully address the Commission's concerns stated in the NOPR. The modified Reliability Standard does not contain Measures or Levels of Non-Compliance corresponding to Requirement 8. This Requirement deals with actions to restore real and reactive power balance. Given the importance of these matters to reliable operations, the Commission directs the ERO to provide Measures and Level of Non-Compliance for this Requirement.

1582. We disagree with California PUC's assertion that the Commission should not adopt TOP–001–1 unless it commits to a policy of ''appropriate deference'' to existing authorities. Approval of a continent-wide Reliability Standard should not be delayed because it may overlap with a local or regional program. Rather, stakeholders should raise related concerns in the ERO Reliability Standards development process. Moreover, section 215(i)(3) of the FPA provides that ''nothing in [section 215] shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard.'' In any event, California PUC does not suggest how the Requirements in TOP–001–1 and the provisions of CAISO's participating generator agreements will lead to conflicting outcomes. To the extent a potential conflict arises, we note that the CAISO's participating generator agreements are subject to Commission jurisdiction, and § 39.6 of the Commission's regulations provides procedures for resolving conflicts between a requirement in a Reliability Standard and a provision of an agreement accepted for filing at the Commission.[400]

1583. We agree with FirstEnergy that TOP–001–1 should establish a clear line of authority. Requirement R3 of Reliability Standard IRO–001–0 clearly establishes the decision-making authority of the reliability coordinator to act and to direct actions to be taken by operating entities to preserve the integrity and reliability of the Bulk-Power System. When an entity is faced with conflicting directives, it must follow the reliability coordinator's directives because the reliability coordinator is the highest authority in matters affecting reliability of the Bulk-Power System. Therefore no changes are required to the Reliability Standard in this connection.

1584. We agree with MEAG Power that a reliability directive to an LSE to increase its planning reserve to 15 percent or to reconductor its transmission line is outside the scope of

[398] California Cogeneration notes that the curtailment of QFs in an emergency is allowed by 18 CFR 292.307.

[399] Santa Clara makes a similar argument reagarding Requirement R3 of TOP–008–1.

[400] *See* 18 CFR 39.6 (Conflict of a Reliability Standard with a Commission Order).

a TOP reliability directive. Reliability directives in the TOP group of Reliability Standards deal with operational directives and not planning directives.

1585. We disagree with MEAG Power that an entity may have to comply with a reliability directive issued to it by a reliability coordinator other than its host reliability coordinator. The operating hierarchy embodied in the Reliability Standard gives the reliability coordinator responsibility and authority to issue reliability directives to its own transmission operators, balancing authorities and generator operators. These entities must comply with these directives as stated in Requirement R3 in TOP–001–1.[401] An entity is only responsible for following directives from its host reliability coordinator unless authority is delegated to another reliability coordinator by the host reliability coordinator.

1586. We agree with FirstEnergy and California Cogeneration that the definition of ''emergency'' could be further clarified. We discuss this issue in this Final Rule in connection with Reliability Standard EOP–001–0 and conclude that emergency states need to be defined and that criteria for entering these states and authority for declaring them need to be specified. We therefore direct the ERO to modify the Reliability Standard accordingly. With respect to California Cogeneration's argument regarding exemptions from the requirement to respond to emergencies, the reliability coordinator must be in a position to take all necessary actions in response to an emergency and is in the best position to determine which entities should respond to its directives.

1587. In response to FirstEnergy's request for clarification of the meaning of ''safety'' in the first sentence of Requirement R4, of TOP–001–1 and whether it refers to safety to the system/equipment, public safety or both, the Commission notes that each term in the series set forth in this provision refers to a type of ''requirement.'' [402] The provision clearly differentiates between the safety of persons and equipment requirements. Since equipment requirements are mentioned separately, safety must be read as referring to requirements related to safety of persons.

1588. With regard to FirstEnergy's proposal that the entity requesting emergency assistance be required to report that it has implemented all of its own emergency procedures as part of its request for emergency assistance, we believe that such reporting is not appropriate during an emergency situation. Requirement R6 of the Reliability Standard clearly specifies that entities must provide available emergency assistance provided the requesting entity has implemented its comparable emergency procedures. Given the nature of emergency situations where time is of the essence, compliance with this Requirement must be assessed after the fact as part of the compliance audit, and not during an emergency.

1589. With respect to Santa Clara's proposal that Requirements R7.2 and R7.3 be revised to provide that the transmission operator may notify the reliability coordinator or the balancing authority that it is removing facilities from service, the Commission directs the ERO to consider Santa Clara's comments in the Reliability Standards development process.

1590. Accordingly, the Commission approves Reliability Standard TOP–001–1. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP–001–1 through the Reliability Standards development process that: (1) Includes Measures and Levels of Non-Compliance for Requirement R8 and (2) considers adding other Measures and Levels of Non-Compliance in the Reliability Standard.

b. Normal Operations Planning (TOP–002–2)

1591. Reliability Standard TOP–002–2 requires transmission operators and balancing authorities to look ahead to the next hour, day and season, and have operating plans ready to meet any unscheduled changes in system configuration and generation dispatch. The Reliability Standard addresses the following matters: (1) Procedures to mitigate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations; (2) verification of real and reactive reserve capabilities; (3) communications; (4) modeling; (5) information exchange and (6) data confidentiality restrictions. The goal of TOP–002–1 is to ensure that resources and operational plans are in place to enable system operators to maintain the Bulk-Power System in a reliable state.

1592. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, the Commission proposed to direct that NERC submit a modification that: (1) Includes Measures and Levels of Non-Compliance; (2) deletes references to confidentiality agreements in Requirements R3 and R4, but addresses the issue separately to ensure that necessary protections are in place related to confidential information and (3) requires next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages.[403]

1593. The Commission also proposed to interpret Requirement R7 of the Reliability Standard as requiring that each balancing authority plan to meet capacity and energy reserve requirements, including deliverability/capability for any single contingency. Although the NERC glossary defines ''contingency,'' [404] the Commission expressed concern in the NOPR that the phrase ''single contingency'' is open to interpretation, and ''deliverability'' is not defined. The Commission proposed in the NOPR to interpret contingency as discussed in connection with the TPL Reliability Standards and to interpret deliverability as the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches.

i. Comments

1594. APPA states that NERC has added Measures for many but not all of the Requirements of TOP–002–2 and needs to develop Measures for Requirements R2, R3, R4, R12 and R17.

1595. Entergy and MidAmerican support the Commission's proposal to delete references to confidentiality agreements from the requirements and state that different approaches must be explored to preserve the confidentiality of data. MidAmerican adds that NERC should adopt an administrative approach to keep the confidential information from being disclosed before the confidentiality provisions are

[401] The Requirement states in part that ''[e]ach Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator* * *.''

[402] Requirement R4 states: ''Each Distribution Provider * * * shall comply with all reliability directives * * * unless such actions would violate safety, equipment, regulatory or statutory requirements.''

[403] In its November 15, 2006, filing, NERC submitted TOP–002–2, which supercedes the earlier Reliability Standard. TOP–002–2 adds Measures and Levels of Non-Compliance to the Reliability Standard, and includes a modified Requirement R14. In this Final Rule, we review the November version, TOP–002–2.

[404] NERC defines ''contingency'' as ''the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electric element.'' NERC Glossary at 3.

deleted from the requirements. LPPC asks the Commission to clarify that CEII remains confidential and states that without such clarification there is a danger that sensitive information related to the Bulk-Power System will become public.

1596. FirstEnergy and Entergy express concerns regarding identifying all control actions in the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency. They contend that system conditions can change significantly between day-ahead analysis and real-time operations, rendering potential control actions irrelevant. Therefore they state that operating entities should be held harmless for not having listed in advance control actions taken in the face of real-time contingencies resulting from unpredicted changing system conditions. APPA states that such requirements are not necessary given that system operators use state estimators and other tools to identify effective control actions that produce more accurate results than would be achieved through the proposed day-ahead analysis. APPA and Entergy assert that it should be left to NERC, as the technical expert charged with setting standards, to decide in the first instance whether such day-ahead analysis would be of sufficient benefit to justify requiring it.

1597. MidAmerican is concerned that the Commission's proposal to interpret the phrase ''single contingency'' as a contingency that includes all multi-element pieces of the system that go out of service together in response to a single event is too restrictive on system operations. However, it also states that historically it has performed the studies in accordance with the Commission's proposal and will support that proposal in the interest of reliability. MidAmerican notes that where a multiple-element single contingency traverses neighboring systems, such contingencies must be coordinated with other systems. Further, it contends that the Commission's directive to have operating plans to meet any scheduled change in system configuration and generation dispatch seems burdensome if not impossible and requests clarification of the Commission's intent in this connection.

1598. ISO–NE recommends that the reference to ''transmission service provider'' in Requirement R12 of TOP–002–2 should be replaced by ''transmission operator'' and/or ''transmission owner.'' [405] It claims that such a change would be consistent with the definition of the term ''transmission service provider,'' which the NERC glossary defines as: ''[t]he entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.'' In performing this function, the transmission service provider provides a business service that entails executing contractual agreements with its customers to provide open access transmission service, whereas SOLs and IROLs are technical in nature and do not translate into transmission service provider functions. In contrast, transmission operators and transmission owners perform planning and operations functions and will need SOL and IROL data.

1599. NRC states that it is not clear whether TOP–002–2 considers the N–1 and the N–1–1 criteria consistent with TPL–002–0 and TPL–003–0, respectively. NRC is concerned about verifying that the Bulk-Power System will provide the necessary voltages to the auxiliary power system busses after a nuclear power plant trip. It suggests that knowledge and verification of significant generator characteristics are essential to this end, especially verification of real and reactive capabilities, automatic voltage regulator status and operating limits. NRC also proposes various revisions to TOP–002–2.

ii. Commission Determination

1600. The Commission approves Reliability Standard TOP–002–2 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process as discussed below.

1601. We are adopting our proposal regarding deletion of references to confidentiality agreements from the Requirements. As we explained in the NOPR, the effectiveness of a Reliability Standard should not be predicated upon the existence of a confidentiality agreement.[406] The ERO should address the confidentiality provision separately to ensure that confidentiality of data is not compromised and CEII information remains confidential.

1602. As noted above, a number of commenters express concerns with the Commission's proposal to require a next-day analysis for all IROLs to identify and communicate control actions to system operators. Identification and communication of control actions that can be implemented within 30 minutes are required to ensure that system operators are aware of and have options available to respond to system conditions following the first contingency to restore the system to a secure state so that it can withstand the next contingency. In addition, the control actions identified in the next-day analysis may quite often be relevant, and informing the system operators of the control options earlier on would be helpful. While the operators may take other actions to preserve the system, they need to have at least one plan (control actions) that will preserve the system from cascading. We believe this addresses FirstEnergy's concern regarding whether compliance requires the use of only the control actions identified in the day-ahead analysis. In response to APPA's comment on the use of state estimators and other tools to identify effective control actions, we note that this capability will help operators in assessing system responses, but they will not identify the control actions system operators will need to take in real-time. Further, operators may not be aware of available control actions, or worse they may not have any control actions, other than firm load-shedding, available to adjust the system after a first contingency occurs. Therefore, we direct the ERO to modify Reliability Standard TOP–002–2 to require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages.

1603. With respect to NRC's comments, system operators must operate the system in front of them at all times to be capable of withstanding a critical contingency (N–1) without resulting in instability, uncontrolled separation or cascading failures. After this N–1 contingency the operators must adjust the system as soon as possible and in no longer than 30 minutes so that the system can then withstand a new N–1 contingency. Further discussion of how this applies in the planning arena is presented in connection with the TPL group of Reliability Standards.

[405] Requirement R12 provides: ''The Transmission Service Provider shall include known SOLs and IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs, and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.''

[406] NOPR at P 976.

1604. The Commission agrees with NRC that the minimum voltages at nuclear plant auxiliary power system buses should be assessed in next-day analysis to ensure that adequate voltages can be maintained in accordance with the nuclear plant minimum voltage requirements. If this assessment projects that the minimum voltage requirements cannot be met, the transmission operators or balancing authorities must notify the nuclear power plant as soon as possible, but in no event later than the commencement of the next day's real-time operations. If during real-time operations the transmission operator cannot maintain the minimum voltage, pre- or post-contingency, it must inform the nuclear plant operator accordingly so that the appropriate corrective actions can be carried out by both the nuclear plant operator and the transmission operator. The Commission directs the ERO to modify Reliability Standard TOP–002–2 to address these two issues.

1605. The Commission proposed in the NOPR that simulations must be consistent with the number of elements that will be removed from service as a result of the failure of a single element.[407] MidAmerican states that it operates consistent with this proposal, in that it respects a single contingency as one that includes all multiple pieces of the elements that go out of service together in response to a single event. Even though MidAmerican states that the Commission's proposal is too restrictive on system operation, it supports the proposal in the interest of reliability. To do otherwise would not represent what actually happens in real-time operations to the detriment of Bulk-Power System reliability, which demonstrates the need to approach the issue as we propose. We discuss this issue further in connection with the TPL group of Reliability Standards, where we direct the ERO to modify the TPL Reliability Standards to simulate what actually happens in the physical system, including multiple element failures.

1606. We note with regard to MidAmerican's comment on operating plans to meet any scheduled change in system configuration and generation dispatch that we have not directed any action in this connection and therefore cannot provide any further clarification on this point. With regard to MidAmerican's comment on coordinated efforts with neighboring systems to deal with multiple element single contingencies, we note that such coordination is already required by IRO and TOP Reliability Standards.

1607. Commenters did not take issue with the proposed interpretation of the term ''deliverability'' as ''the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches.'' [408] The Commission adopts this proposed interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP–002–2 should be understood in this manner.

1608. With respect to the modifications to Requirement R12 of the Reliability Standard recommended by ISO–NE and NRC's comments on Measure M7 and a new Measure M11, the Commission directs the ERO to consider these matters in the Reliability Standards development process. In response to NRC's suggestion regarding periodic review of generators' reactive capability, we note that Reliability Standard MOD–025–1 already requires periodic review of generators' reactive capability.

1609. As we explained in the NOPR, TOP–002–2 serves an important purpose in ensuring that resources and operational plans are in place to enable system operators to maintain the Bulk-Power System in a reliable state. Further, the requirements set forth in the Reliability Standard are sufficiently clear and objective to provide guidance for compliance. Accordingly, the Commission approves Reliability Standard TOP–002–2. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP–002–2 through the Reliability Standards development process that: (1) Deletes references to confidentiality agreements in Requirements R3 and R4, but addresses the issue separately to ensure that necessary protections are in place related to confidential information; (2) requires the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages; (3) requires next-day analysis of minimum voltages at nuclear power plants auxiliary power busses and (4) requires simulation contingencies to match what will actually happen in the field.

c. Planned Outage Coordination (TOP–003–0)

1610. Reliability Standard TOP–003–0 requires transmission operators that operate facilities greater than 100 kV, generator operators that operate facilities greater than 50 MW and balancing authorities to coordinate transmission and generator maintenance schedules. Where a conflict in maintenance schedule arises, the reliability coordinator is authorized to resolve the conflict.

1611. The Commission proposed in the NOPR to approve Reliability Standard TOP–003–0 as mandatory and enforceable. The Commission also proposed to direct NERC to submit a modification to TOP–003–0 that: (1) Includes a requirement to communicate scheduled outages well in advance to ensure reliability and accuracy of ATC calculation and (2) makes any facility below the 100 kV or 50 MW thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, will have a direct impact on the operation of Bulk-Power System subject to Requirement R1 for planned outage coordination.

1612. In addition, the Commission noted in the NOPR that outage information is important to both reliable operation and to the calculation of ATC. This information is also needed to assure coordination of outages long before next day or current day operations. The Commission proposed that applicable scheduled outages be communicated to affected transmission operators and reliability coordinators with sufficient lead time to coordinate outages. The Commission then requested industry input on what constitutes sufficient lead time for planned outages.

i. Comments

1613. MRO, APPA and others raise concerns requiring the proposed requirement to communicate scheduled outages ''well in advance.'' APPA cautions that TOP–003–0 was generally designed to ensure that transmission operators receive accurate and timely information about transmission and generation outages affecting ''next-day operations,'' rather than the longer term outage planning information. MRO states that requiring outage information well in advance reduces the entity's flexibility for other contingencies and changes. MRO also contends that the phrase ''well in advance'' is vague, not measurable, and may not be enforced fairly and consistently. FirstEnergy states that NERC should specify the meaning of ''well in advance'' through its Reliability Standards development process with industry input. MRO recommends that the time period for outage notification should be based on the size of the generating facility and voltage level of the transmission line so

[407] NOPR at P 979.

[408] *Id.* at P 974.

that a larger facility has a longer lead time for outage notification.

1614. While MISO agrees with the need for early notification of planned outages, it is concerned that an arbitrary lead time will cause entities to postpone needed maintenance to accommodate the timeline, thereby reducing the reliability of the Bulk-Power System.

1615. LPPC states that business reasons often drive a longer lead time for outage planning to allow market participants to better understand the congestion and market impacts of the planned outage. LPPC believes that the Commission should exercise caution and avoid adopting a business practice as part of the Reliability Standard. Reliability concerns often dictate that an outage should not be planned and set in stone too far in advance because the circumstances may change. According to LPPC, the Commission should refrain from prescribing a lead time that would cut into an operator's flexibility, which is needed to respond to real-time situations.

1616. In response to the Commission's question regarding the lead time for planned outages, MidAmerican states that although it believes that a requirement for extending the lead time will result in higher costs and less flexibility, a two-week advance notice for planned outages of 345 kV facilities and one-week advance notice for 161 and 69 kV facilities is appropriate. TVA proposes one-week advance notice for all planned outages and recommends that TOP–003–0 should be modified to include breaker outages within the meaning of the facilities that are subject to advance notice for planned outages.

1617. CAISO states that its current tariff provides for three days of lead time for providing outage information and that this is a standard practice throughout WECC. It maintains, however, that the three-day lead time is not sufficient for the needed review and coordination of outages. In fact, CAISO states that many ISOs and RTOs are moving toward a lead time of either 30 days or 45 days prior to the beginning of the outage month. CAISO contends that rather than basing the outage information on a certain kV level, the emphasis should be on facilities that may have a significant effect on congestion revenue rights resource adequacy.

1618. Entergy and FirstEnergy support the proposed modification to include any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, will have a direct impact on the operation of the Bulk-Power System subject to Requirement R1 for planned outage coordination. They maintain that such a modification will provide the transmission operator much needed flexibility. APPA, on the other hand, opposes the proposal. APPA states that the Commission should allow the ERO in the first instance to consider whether to add this specific requirement to TOP–003–0. If the Commission is concerned that TOP–003–0 as it now stands might ''not include all facilities that have a significant impact on the operation of the Bulk-Power System,'' it should direct NERC to consider that issue on remand using its Reliability Standards development process.

1619. Xcel notes that Requirement R4 of the Reliability Standard provides that each reliability coordinator should resolve any potential conflicts in scheduling of planned outages. Xcel argues that if a reliability coordinator requires an entity to move its planned outage to accommodate another entity's unplanned outage, the entity that agrees to move its planned outage to another time should receive compensation.

ii. Commission Determination

1620. The Commission approves TOP–003–0 as mandatory and enforceable. We address the concerns raised by commenters below.

1621. In Order No. 890, the Commission directed that information concerning ATC calculations be consistent and transparent.[409] The timing of facility outages is one important piece of information in ATC calculations. In Order No. 890, the Commission directed that specific data be exchanged among transmission providers, including transmission planned and contingency outages, for the purpose of ATC modeling.[410] Consistent with this determination in Order No. 890, the Commission directs the ERO to develop a modification to TOP–003–0 that requires the communication of scheduled outages to all affected entities well in advance to ensure reliability and accuracy of ATC calculations.[411] We believe this addresses LPPC's concern regarding the interplay between reliability and business practices.

1622. Several commenters raised concerns regarding the Commission's proposal to require outage information well in advance. Specifically, they argue that the term ''well in advance'' is vague, that the requirement would reduce flexibility and that it would cause entities to postpone needed maintenance work, thereby reducing reliability. In response to the Commission's request for comments on lead time for planned outages, entities provide information on current lead time practices indicating that lead times range from one week to 45 days. We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages. The ERO should utilize the information filed by commenters in the Reliability Standards development process. In doing so the ERO should take into consideration the need for flexibility, as well the lead time required for coordination with other entities and outage assessments. Proper coordination will ensure that priority is given to needed maintenance work for critical facilities to ensure reliability.

1623. With regard to TVA's request to include breaker outages within the meaning of the facilities that are subject to advance notice for planned outages, we direct the ERO to consider this suggestion in the Reliability Standards development process.

(a) Applicability

1624. As noted above, the Commission proposed to direct the ERO to modify TOP–003–0 to make any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, will have a direct impact on the operation of Bulk-Power System subject to Requirement R1 for planned outage coordination.

1625. Entergy and FirstEnergy support the proposed modification to include any facility below the threshold that in the opinion of the reliability coordinator, balancing authority or transmission operator will have a direct impact on the operation of the Bulk-Power System. On the other hand, APPA opposes this proposal and contends that the Commission should allow the ERO, as the expert entity charged with developing Reliability Standards, to consider whether to add this specific requirement. The Commission disagrees because registered entities below the thresholds currently defined in Requirement R1 of the Reliability Standard may have an impact on reliability and therefore should be required to submit data on their planned outages. The Commission therefore directs the ERO to modify the

[409] *See* Order No. 890 at P 68–69, 207–213.

[410] *Id.* at P 292.

[411] The Commission notes that PJM has developed an outage scheduling process in response to Commission directives to avoid the possibility of undue discrimination. *http://www.pjm.com/committees/mrc/downloads/20060630-item-06-draft-manual-14b-changes.pdf.* The outage scheduling process was developed through a stakeholder process and has been utilized in the entire PJM footprint for a number of years. PJM's outage scheduling program is one example of the type of program that should be implemented through the Reliability Standard.

Reliability Standard to require that any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator will have a direct impact on the reliability of the Bulk-Power System be subject to Requirement R1 for planned outage coordination.

(b) Other Issues

1626. In response to Xcel's proposal that entities that agree to reschedule their previously-approved planned outages to accommodate another entity's unplanned outage be compensated, the Commission notes that whereas rescheduling of the outage is a reliability matter, compensation is not and therefore is outside the scope of this proceeding.

(c) Summary of Commission Determination

1627. Planned outage coordination is a necessary element of reliable operations, and TOP–003–0 promotes that goal. Accordingly, the Commission approves the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP–003–0 through the Reliability Standards development process that: (1) Includes a new requirement to communicate longer term outages well in advance to ensure reliability and accuracy of ATC calculation; (2) makes any facility below the voltage thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, will have a direct impact on the operation of Bulk-Power System, subject to Requirement R1 for planned outage coordination and (3) incorporates an appropriate lead time for planned outages as discussed above.

d. Transmission Operations (TOP–004–1)

1628. This Reliability Standard requires transmission operators to operate the transmission system within SOL and IROL.[412] The N–1 operating criterion for the transmission system is also established in this Reliability Standard. It provides that operating configurations for which limits have not yet been determined should be treated as emergencies. The goal of the Reliability Standard is to maintain Bulk-Power System facilities within limits, thereby protecting transmission, generation, distribution and customer equipment and preventing cascading failures of the interconnected grid.

1629. The Commission proposed in the NOPR to approve the Reliability Standard as mandatory and enforceable. In addition, the Commission proposed to direct that NERC submit a modification that: (1) Includes Measures and Levels of Non-Compliance; (2) clarifies that the system should be restored as soon as possible, taking no more than 30 minutes and (3) defines high risk conditions under which the system must be operated to respect multiple outages in Requirement R3. The Commission also proposed to direct the ERO to perform a survey of the prevailing operating practices and actual operating experiences surrounding drifting in and out of IROL limits.

1630. Requirement R3 requires that each transmission operator shall, when practical, operate the system to respect multiple outages as specified by the regional reliability organization policy. The Commission noted in the NOPR that Requirement R3 does not define conditions under which multiple outages must be considered. The NOPR proposed to interpret such conditions ''to include high risk conditions such as hurricanes, ice storms or periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage.'' [413]

i. Comments

1631. PG&E and APPA oppose a modification to the Reliability Standard that changes the requirement allowing operators to return the system to a reliable operating state within 30 minutes to a requirement that they do so as soon as possible and in no longer than 30 minutes. PG&E is concerned that during emergencies operators would be subject to uncertainty in complying with such a requirement, which could lead to overly hasty responses with a corresponding detrimental effect on reliability. PG&E states that to avoid the confusion and ambiguity from a subjective standard, the Commission and NERC should only clarify that operators should seek to return the system to a reliable operating state as soon as possible, but maintain the current requirement of 30 minutes as stated in Requirement R4 of TOP–004–1. APPA states that if the Commission is concerned about the need to require a response time that is quicker than 30 minutes, it should direct the ERO to consider this issue as part of the Reliability Standards development process.

1632. Entergy and MidAmerican support the Commission's proposal to have NERC conduct a survey and report the operating practices and actual experiences surrounding drifting in and out of IROL violations. MISO, on the other hand, opposes the survey because there are already requirements for reporting IROL violations elsewhere in the Reliability Standards. APPA proposes that the Commission should ask the ERO to determine if such information would improve reliable operations. If it is determined that such information will improve reliability, NERC should include this type of information in compliance violation reporting procedures.

1633. LPPC and Xcel recommend that the Commission not require NERC to define in Requirement R3 the specific high-risk conditions under which the system must be operated to respect multiple outages. Xcel argues that it is unnecessary and impractical to attempt to define in advance all of the possible scenarios that will result in a high-risk condition. Not all high-risk conditions can be defined at any one time because changes in the system will introduce new high-risk conditions. Even if a list of high-risk conditions is developed, then, by definition, all other conditions not listed are excluded from consideration under this Reliability Standard. LPPC states that the proposed modification to deal with high-risk conditions is an unnecessarily prescriptive approach and could be detrimental to reliability by excluding scenarios that should be listed under this Requirement.

1634. California PUC states that the Commission should not interpret hurricanes and ice storms as high risk conditions for studying multiple outages because events such as hurricanes and ice storms actually reduce the stress on the Bulk-Power System. This is because such events cause outages at the local distribution system level. California PUC maintains that since events such as hurricanes and ice storms rarely cause cascading outages, the proper approach for dealing with such situations is to focus on system restoration planning rather than including them in the contingency analysis that the proposed modification will require as a result of including such natural events within the meaning of high risk conditions.

1635. Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include

[412] In its November 15, 2006, filing, NERC submitted TOP–004–1, which has an effective date of October 1, 2007, at which time it will supercede the Version 0 Reliability Standard. TOP–004–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. Because TOP–004–0 will be in effect until October 1, 2007 and TOP–004–1 thereafter, we address both versions of the Reliability Standard.

[413] NOPR at P 997.

frequency monitoring in addition to the monitoring of voltage, real and reactive power flows.

ii. Commission Determination

1636. The Commission approves TOP–004–0 as mandatory and enforceable until October 1, 2007, when TOP–004–1 will be mandatory and enforceable. We address the concerns raised by commenters below.

1637. We adopt our proposal to require the ERO to clarify that the system should be restored as soon as possible, taking no more than 30 minutes. Requirement R4 of TOP–004–1 (as well as the Version 0 standard) provides that if a transmission operator enters an unknown state, *i.e.,* any state for which valid operating limits have not been determined, operations should be restored to respect proven reliable power system limits within 30 minutes. However, as we stated in the NOPR, this language may be interpreted as a grace period to the detriment of reliability.[414] The Commission, therefore, directs that the ERO develop a modification to Requirement R4 providing that the system should be restored to respect proven reliable power system limits as soon as possible and in no longer than 30 minutes. In response to PG&E's point that the phrase ''as soon as possible'' would add confusion, we note that Measure M1 in TOP–004–1 would measure performance against the 30-minute period specified in Requirement R4.

1638. Entergy and MidAmerican support our proposal to direct the ERO to conduct a survey and report the operating practices and actual experiences surrounding drifting in and out of IROL violations. We disagree with MISO that TOP–007–0 covers reporting of ''drifting'' in and out of IROL violations because that Reliability Standard only requires reporting of IROL violations exceeding 30 minutes. With regard to APPA's suggestion that NERC should determine whether such information would improve reliable operations, we believe a survey is appropriate to determine actual practices, and simply modifying the compliance reporting procedures may not provide sufficient data to determine the reliability impacts of such practices and whether a modification to the Reliability Standard is appropriate. Accordingly, we direct the ERO to conduct a survey on the operating practices and actual experiences surrounding drifting in and out of IROL violations. Such a survey will provide factual support for whether additional modifications to the Reliability Standard are needed. The survey will also indicate whether additional vigilance on the part of compliance auditors is warranted in this area to ensure Bulk-Power System reliability.

1639. As mentioned above, the Commission proposed to interpret ''multiple outages'' in the context of Requirement R3 to include multiple element outages resulting from high-risk conditions such as hurricanes, wild fires, ice storms or periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under the high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N–1 criterion because the probability of multiple outages during high-risk conditions approaches that of a single outage during normal conditions. This does not preclude development of restoration plans as suggested by California PUC. Thus, we direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process.

1640. We direct the ERO to consider Santa Clara's suggestion regarding changes to Requirement R2 in the Reliability Standards development process.

1641. Accordingly, the Commission approves Reliability Standard TOP–004–0. Further, we approve TOP–004–1 so that it will become mandatory and enforceable on the stated effective date of October 1, 2007. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to the Reliability Standard through the Reliability Standards development process that: (1) Modifies Requirement R4 to state that the system should be restored to respect proven limits as soon as possible, taking no more than 30 minutes and (2) defines high risk conditions under which the system must be operated to respect multiple outages in Requirement R3, consistent with the discussion above.

1642. In addition, the Commission directs the ERO to perform a survey of the prevailing operating practices and actual operating experiences surrounding drifting in and out of IROL limits as discussed more fully in this Final Rule in connection with the IRO group of Reliability Standards. As an example of the type of data that would be appropriate in the survey, we would expect to have reliability coordinators report any violation of an IROL not exceeding 30 minutes, its causes, the date and time of the violation, and the duration for which actual operations exceeded IROL to the ERO on a monthly basis for one year beginning two months after the effective date of the Final Rule. The ERO should report the results to the Commission in an informational filing within 18 months from the effective date of this Final Rule.

e. Operational Reliability Information (TOP–005–1)

1643. Reliability Standard TOP–005–1 seeks to ensure that reliability information is shared among reliability coordinators, transmission operators and balancing authorities. It requires the transmission operator and the balancing authority to provide operating data to each other and to the reliability coordinator, and it provides a list of typical operating data that must be provided. TOP–005–1 also provides that each data recipient must execute a confidentiality agreement as a condition of receiving data from NERC's Interregional Security Network.[415]

1644. The Commission proposed in the NOPR to approve Reliability Standard TOP–005–1 as mandatory and enforceable. The Commission also proposed to direct NERC to submit a modification to TOP–005–1 that: (1) Includes information about the operational status of special protection systems and power system stabilizers in Attachment 1 and (2) deletes references to confidentiality agreements, but addresses the issue separately to ensure that necessary protections are in place related to confidential information.

i. Comments

1645. FirstEnergy states that TOP–005–1 should also apply to transmission providers because some of the information listed in Attachment 1 to the Reliability Standard is in their possession. Attachment 1 should be modified so that it allows each entity to know what data it is expected to provide. As currently written, Attachment 1 lists various entities that are supposed to provide data without

[414] *See* NOPR at P 995.

[415] Interregional Security Network is a data exchange system that facilitates the exchange of real-time and other operational data among reliability coordinators, balancing authorities and transmission operators to help ensure reliable electric power system operations.

specifying who will provide which information. FirstEnergy states that transmission operators, for example, may not have all the information listed in item 1.5 of Attachment 1.

1646. APPA and Entergy agree that TOP–005–1 should be modified to include information about the operational status of special protection systems and power system stabilizers in Attachment 1. However, APPA contends that the Commission's directive should be revised so that this change is developed through the Reliability Standards development process.

1647. ISO–NE recommends that the reference to ''purchasing-selling entity'' in Requirement R4 should be replaced with ''generator owner, transmission owner, and LSE.'' [416] It argues that since NERC's glossary defines the term ''purchasing-selling entity'' as ''[t]he entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operation services,'' many entities can fall within this category (*e.g.*, commodity traders such as financial/power marketers) that may possess little or none of the operational or reliability data the host balancing authority and transmission operator need to conduct reliability assessments.

1648. A number of commenters discussed the Commission's proposal to delete references to confidentiality agreements in the Reliability Standard but to address the issue separately to ensure that necessary protections are in place related to confidential information. Those comments are summarized above in connection with the same proposal made by the Commission in the case of TOP–002–1.

ii. Commission Determination

1649. For the reasons stated in the NOPR,[417] we direct the ERO to develop a modification to TOP–005–1 through the Reliability Standards development process regarding the operational status of special protection systems and power system stabilizers in Attachment 1. Several commenters agree with this directive, and we believe that this information will provide a more comprehensive list in Attachment 1.

1650. We are adopting our proposal regarding deletion of references to confidentiality agreements from the Requirements. Our discussion of this matter in connection with TOP–002–1 applies equally here.

1651. The Commission directs the ERO to consider FirstEnergy's recommended modifications to Attachment 1 to the Reliability Standard and ISO–NE's recommended revision to Requirement R4 in the Reliability Standards development process.

1652. Accordingly, the Commission approves Reliability Standard TOP–005–1. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP–005–1 through the Reliability Standards development process that: (1) Includes information about the operational status of special protection systems and power system stabilizers in Attachment 1 and (2) deletes references to confidentiality agreements, but addresses the issue separately to ensure that necessary protections are in place related to confidential information.

f. Monitoring System Conditions (TOP–006–1)

1653. TOP–006–1 requires operating personnel to continuously monitor essential Bulk-Power System parameters such as line flows, circuit breaker status, generator resources, relays, weather forecasts and frequency to ensure that the facilities do not exceed their operating limits.

1654. The Commission proposed in the NOPR to approve the Reliability Standard as mandatory and enforceable.[418] The Commission also proposed to direct NERC to submit a modification that: (1) Includes Measures and Levels of Non-Compliance; (2) includes a new Requirement related to the provision of a minimum set of analytical tools that will aid in situational awareness and (3) clarifies the meaning of ''appropriate technical information'' concerning protective relays.

i. Comments

1655. Dominion supports including a new requirement for a minimum set of analytical tools. It argues that such a requirement will ensure that operators have a minimum set of tools with which to perform their duties. The Reliability Standard should also specify metrics that can be audited, such as minimum availability times, so that these tools are adequately maintained. However, Alcoa states that requiring a minimum set of tools will be unduly onerous, especially to smaller balancing authorities and transmission operators. Although situational awareness tools, such as state estimators, are critical for an ISO and RTO, smaller balancing authorities and transmission operators should provide necessary data to the reliability coordinator that monitors a wide region using such tools.

1656. Alcoa claims that developing additional capability at the balancing authority and transmission operator levels when such capability already exists at the reliability coordinator level will be redundant. Requiring state estimation for a small balancing area that is under an ISO would provide little benefit for grid reliability since the scope of the balancing area's visibility is limited.

1657. APPA does not support the proposed requirement related to the provision of a minimum set of analytical tools and claims that inclusion of specific analytical tools is counterproductive because the tools become obsolete within two to five years due to technical advances. APPA states that deciding whether to add a new requirement for a minimum set of analytical tools should be left to NERC in the first instance. Similarly, TAPS argues that NERC should consider in the first instance whether minimum analytical tools are necessary and for what subset of generator operators and transmission operators.

1658. LPPC maintains that the Commission should require NERC to list the capabilities required rather than specific tools because tools will change over time.

1659. APPA states that the ERO's filing on November 15, 2006 includes new Measures M1 through M6, which only measure Requirements R1, R2, R4, R5 and R7.

ii. Commission Determination

1660. The Commission approves TOP–006–1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to TOP–006–1 through the Reliability Standards development process, as discussed below.

1661. We adopt our proposal to require the ERO to develop a modification related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System. In response to APPA that the inclusion of specific analytical tools is counterproductive because the tools

[416] Requirement R4 states: ''Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.''

[417] NOPR at P 1005.

[418] In its November 15, 2006 filing, NERC submitted TOP–006–1, which supersedes the Version 0 Reliability Standard. TOP–006–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, TOP–006–1.

will become obsolete, we note that we are not seeking specific analytical tools, but rather minimum capabilities.

1662. In regard to Alcoa's concern that this new Requirement would be unduly onerous, especially for smaller balancing authorities and transmission operators, the Commission's intent is not to subject smaller balancing authorities and transmission operators to the same requirements placed on larger balancing authorities and transmission operators. As part of the modification of this Reliability Standard to develop a new requirement for minimum capability for analytical tools, the ERO should take into account what would be required of smaller balancing authorities and transmission operators for the Reliable Operation of the Bulk-Power System, instead of applying the same requirements as are placed on other reliability entities such as reliability coordinators and larger balancing authorities and transmission operators.

1663. We disagree with Alcoa that developing additional capability at the balancing authority and transmission operator levels when such capability already exists at the reliability coordinator level will be redundant. We are not seeking to duplicate the same capability for each reliability entity, but rather the new requirement should specify the minimum capability taking into account the role played by each entity. For example, a reliability coordinator may need to have access to state estimator and contingency analysis whereas a generator operator may not need these capabilities.[419]

1664. No commenters addressed our proposal with respect to the meaning of ''appropriate technical information'' concerning protective relays in Requirement R3 of the Reliability Standard. To provide more clarity, criteria that define what ''appropriate technical information'' is necessary should be specified so that operators can make better informed decisions. An example of such information would be the allowable reclosing angle set in the existing relays and the maximum angle at specific points in the Bulk-Power System that would be acceptable to allow closing of lines during system restoration.

1665. The ERO should consider APPA's comment regarding the missing Measures in the ERO's Reliability Standards development process.

1666. Accordingly, the Commission approves Reliability Standard TOP–006–1. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP–006–1 through the Reliability Standards development process that: (1) Includes a new requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System and (2) clarifies the meaning of ''appropriate technical information'' concerning protective relays.

g. Reporting SOL and IROL Violations (TOP–007–0)

1667. TOP–007–0 requires that violations of SOL and IROL be promptly reported to the reliability coordinator so that it can direct corrective action and inform other affected systems. It also requires a transmission operator to mitigate an IROL violation as soon as possible but in no longer than 30 minutes. A transmission operator must take ''all appropriate actions up to and including shedding firm load'' to return its system to a stable state within IROL. Finally, the Reliability Standard requires that the reliability coordinator take action to mitigate an SOL or IROL violation if the transmission operator's actions are not effective.

1668. The Commission proposed in the NOPR to approve TOP–007–0 as mandatory and enforceable.

1669. In the NOPR, the Commission solicited comment on potentially overlapping matters addressed in Reliability Standards TOP–007–0 and TOP–008–0.

i. Comments

1670. NERC recognizes that there are some redundancies and awkward relationships among the various Reliability Standards, which are the result of the translation from the previous operating policies where each policy was treated as a separate set of concepts. NERC states that its 2007–2009 Reliability Standards Work Plan addresses work to be done to eliminate redundancies and better organize the Requirements across Reliability Standards so as to provide a more logical presentation.

1671. APPA states that the concerns expressed in the NOPR about overlapping matters between TOP–007–0 and TOP–008–0 should be referred to the NERC Reliability Standards development process to better comport with the statutory division of responsibility. FirstEnergy and SoCal Edison state that Requirements R2 through R4 are clearly not reporting activities and should be combined with the requirements of TOP–008.

1672. NRC states that some nuclear power plant voltage requirements would result in SOL, *i.e.*, the nuclear power plant voltage limits would be an SOL as a result of the minimum and maximum voltages required at the nuclear power plant switchyard, which typically has a tighter operating band (a higher minimum and a lower maximum) than other nodes in the system. It therefore recommends adding a new requirement that states as follows: ''Following discovery of a potential contingency that could result in an SOL being exceeded at a nuclear power plant (*e.g.*, at post-trip voltage), the transmission owner shall notify the nuclear power plant operator as soon as possible but not longer than 30 minutes if the contingency has not been corrected.'' NRC also suggests modifying the Measures and Compliance sections and Table 1 to account for the new requirement, and provides specific language to be included in those places.

ii. Commission Determination

1673. The Commission approves TOP–007–0 as mandatory and enforceable. We agree with APPA, FirstEnergy and SoCal Edison that the Reliability Standards would benefit from the elimination of overlapping matters in TOP–007–0 and TOP–008–1. The ERO indicates that it plans to address this as part of its Work Plan and this suffices.

1674. NRC has raised some significant issues regarding the consideration of nuclear power plants voltage requirements. Consistent with our general approach in this Final Rule, we direct the ERO to consider NRC's comments in the Reliability Standards development process when addressing TOP–007–0 as part of its Work Plan.

1675. Accordingly, the Commission approves Reliability Standard TOP–007–0 as mandatory and enforceable.

h. Response to Transmission Limit Violations (TOP–008–1)

1676. TOP–008–1 requires a transmission owner to take immediate steps to mitigate SOL and IROL violations.

1677. The Commission proposed in the NOPR to approve Reliability Standard TOP–008–0 as mandatory and enforceable. The Commission also proposed to direct that NERC submit a modification to TOP–008–0 that: (1) Includes Measures and Levels of Non-Compliance and (2) includes reliability

[419] We note that TOP–006–0 applies to transmission operators, balancing authorities, generator operators and reliability coordinators.

coordinators in the applicability section.[420]

i. Comments

1678. APPA questions whether TOP–008–1 should be modified to apply to reliability coordinators. It claims that the Requirement R3 simply mentions that the reliability coordinator will receive information provided by the transmission operator and does not play any substantive role under TOP–008–1. MISO notes that the reliability coordinators' responsibility related to IROL violations are outlined in connection with IRO Reliability Standards and the reasons for adding the reliability coordinator as applicable entity in multiple locations is unclear.

1679. APPA states that NERC has not submitted a Measure for the Requirement R2 of the Reliability Standard. The new Measures M1 through M5 included in TOP–008–1 only measure Requirements R1, R3, and R4. In addition, the data retention and compliance levels reference Measures M1 through M5. Therefore, an entity subject to TOP–008–1 could arguably comply with Requirements R1, R3 and R4 and be in compliance with the entire Reliability Standard.

ii. Commission Determination

1680. For the reasons stated in the NOPR,[421] the Commission approves TOP–008–1 as mandatory and enforceable. We address the concerns raised by commenters below.

1681. We agree with APPA that the reliability coordinator merely receives information provided by the transmission operator and does not play any substantive role under TOP–008–1. We also agree with MISO that the reliability coordinators' responsibility related to IROL violations are outlined in connection with the IRO Reliability Standards and therefore there is no need to modify the applicability section of TOP–008–1 to include the reliability coordinator.

1682. The ERO should consider APPA's comment regarding the missing Measures in the ERO's Reliability Standards development process.

1683. Accordingly, the Commission approves Reliability Standard TOP–008–1 as mandatory and enforceable.

12. TPL: Transmission Planning

1684. The Transmission Planning (TPL) group of Reliability Standards consists of six Reliability Standards that are applicable to transmission planners, planning authorities and regional reliability organizations. These Reliability Standards are intended to ensure that the transmission system is planned and designed to meet an appropriate and specific set of reliability criteria. Transmission planning is a process that involves a number of stages including developing a model of the Bulk-Power System, using this model to assess the performance of the system for a range of operating conditions and contingencies, determining those operating conditions and contingencies that have an undesirable reliability impact, identifying the nature of potential options, and the need to develop and evaluate a range of solutions and selecting the preferred solution, taking into account the time needed to place the solution in service. The proposed TPL Reliability Standards address: (1) The types of simulations and assessments that must be performed to ensure that reliable systems are developed to meet present and future system needs [422] and (2) the information required to assess regional compliance with planning criteria and for self-assessment of regional reliability.[423]

1685. The TPL group of Reliability Standards contains a table designated ''Table 1'' (Transmission System Standards—Normal and Emergency Conditions), which is a key part of this group of Reliability Standards. It lays out the system performance requirements for a range of contingencies grouped according to the number of elements forced out of service as a result of the contingency. For example: Category A applies to the normal system with no contingencies; Category B applies to contingencies resulting in the loss of a single element, defined as a generator, transmission circuit, transformer, single DC pole with or without a fault; Category C applies to a contingency resulting in loss of two or more elements, such as any two circuits on a multiple circuit tower line or both poles of a bi-polar DC line; while Category D applies to extreme contingencies resulting in loss of multiple elements, such as a substation or all lines on a right-of-way. The system performance expectations for Category C contingencies are lower than those for Category B contingencies, in that they allow unspecified amounts of planned or controlled loss of load.

a. General Issues

1686. Commenters raise a number of issues that apply generally to Reliability Standards TPL–001–0 through TPL–004–0. These issues are related to the transmission planning process, sensitivity studies and critical system conditions, element-based versus event-based contingencies, spares strategy, and resource information for planning and sharing information with neighboring systems. We address these general issues here, and the conclusions reached will apply to our discussion of individual TPL Reliability Standards.

i. Transmission Planning Process

1687. The Commission stated in the NOPR that the Reliability Standards are not intended to make the Bulk-Power System failure-proof.[424] In addition, we did not propose to modify the TPL Reliability Standards to require that the system be able to withstand all multiple-contingency and extreme contingency events without loss of load. Nonetheless, we stated that we believe that the planning-related Reliability Standards could be improved to better account for probable contingencies when conducting planning studies. Much of our proposal was consistent with the potential improvements NERC recognized in its comments on the Staff Preliminary Assessment. In addition, we noted that a number of regions currently utilize superior planning practices that may be characterized as ''best practices'' and are more stringent than the proposed TPL Reliability Standards.[425] Accordingly, we proposed that the ERO submit to the Commission such regional differences in transmission planning criteria that are more stringent than those specified in the TPL group of Reliability Standards.

(a) Comments

1688. EEI and APPA strongly believe that the transmission planning processes performed under these Reliability Standards have served this nation extremely well. The Reliability Standards have evolved with changes in industry structure, computer and

[420] In its November 15, 2006, filing, NERC submitted TOP–008–1, which supersedes the Version 0 Reliability Standard. TOP–008–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, TOP–008–1.

[421] *See* NOPR at P 1035–36.

[422] *See* TPL–001–0, TPL–002–0, TPL–003–0 and TPL–004–0.

[423] *See* TPL–005–0 and TPL–006–0.

[424] NOPR at P 1042.

[425] Examples include practices cited in NERC's ''Examples of Excellence'' found in its Readiness Audits (available at *http://www.nerc.com*) and filings for jurisdictional utilities in Part 4 of FERC Form No. 715, Transmission Planning Reliability Criteria. Regional reliability organizations also specify requirements that exceed NERC Reliability Standards, such as WECC's Minimum Operating Requirement Criteria and the NPCC Document A–02—Basic Criteria for Design and Operation of Interconnected Power Systems.

communications technology, electric generation and transmission technology and a broad range of state and federal regulatory demands. EEI and APPA state that it is unclear whether the Commission is proposing a significant expansion of this reliability planning process, which would amount to a fundamental shift in the nature of that process, or whether the Commission is proposing a more specific description of today's comprehensive planning approach. EEI and APPA state that they can interpret the Commission's proposal either as suggesting that planning should support a robust and flexible network that can ''bend'' to a broad range of critical system conditions, as practiced up to now, or that planning should be ''finely tuned'' so that reliability can be maintained under conditions where both resources and loads are highly controlled. They find the source for the latter interpretation in the Commission's request that the industry move toward more explicit requirements that transmission planners consider the effects of load control or other forms of DSM, or conduct planning studies for far more combinations of resource alternatives. EEI and APPA state that the existing Reliability Standards fully meet the Commission's criteria as set forth in Order No. 672, unless the Commission envisions a very different transmission system planning process or seeks to move away from current network design toward the development of a much ''tighter'' transmission system through substantially higher saturations of controllable resources and loads.

1689. SDG&E notes that the NOPR's characterization of the dual objectives of ''appropriateness'' and ''specificity'' speaks, on the one hand, to the need for Reliability Standards that are tailored to each transmission planner's area of responsibility, and, on the other hand, clear, consistent and workable rules. SDG&E urges the Commission to be mindful of the need to assess and balance these considerations in future iterations of the transmission planning Reliability Standards.

1690. Northern Indiana states that the presentation of TPL–001–0 through TPL–004–0 as individual Reliability Standards creates a great deal of confusion. In practice, most transmission planners take an integrated view of these Reliability Standards and treat them as if they were a single standard. Accordingly, Northern Indiana suggests that the Commission ask NERC to file a substitute proposal that would integrate the transmission planning standards and improve their clarity and quality.

1691. SDG&E supports the Commission's proposal to direct NERC to submit for approval regional transmission planning criteria that have been adopted and extensively used that are more stringent than those specified in the current TPL Reliability Standards. NCPA states that whenever a RTO/ISO adopts criteria that differ from ERO or regional standards, those criteria should be made public and transparent.

(b) Commission Determination

1692. EEI and APPA raise an important question on the Commission's intent regarding the transmission planning process and proposed modifications to the transmission planning standards. They ask whether the Commission is proposing a fundamental shift in the nature of the planning process that would result in a move away from the current network design towards a much ''tighter'' transmission system through substantially increased use of controllable resources and loads. The Commission is not proposing a fundamental shift in the nature of the planning process as it is practiced today. We clarify that all the proposed modifications to the TPL group of Reliability Standards are aimed at ensuring Reliable Operation of the Bulk-Power System. To achieve this goal, it is necessary, among other things, to ensure that the planning process and the Reliability Standards produce a Bulk-Power System that is robust enough to be able to withstand a range of probable contingencies while reliably serving customer demand and preventing the identified outages, and flexible enough to accommodate a broad range of system conditions over a planning horizon that takes into account lead times to place facilities in service. Further, the proposed modifications are intended to ensure that the planning requirements are specific enough to promote rigor and consistency in assessments and provide clear and measurable rules for mandatory and enforceable Reliability Standards. The Commission therefore agrees with SDG&E's comments in this regard and on the need to balance ''appropriateness'' and ''specificity.''

1693. The Commission agrees with Northern Indiana that the Reliability Standards TPL–001–0 through TPL–004–0 would be improved if they were integrated into a single Reliability Standard. Such an approach conforms more closely to common planning practices, and integrating these Reliability Standards therefore could enhance their practical effectiveness. The Commission notes that the Work Plan submitted by the ERO has earmarked this group of Reliability Standards for revision during the early stages of the plan. The Commission directs the ERO to consider integrating Reliability Standards TPL–001–0 through TPL–004–0 into a single Reliability Standard through the Reliability Standards development process.

1694. The Commission agrees with SDG&E and NCPA that any criteria that are more stringent than the ERO planning criteria should be made public and transparent. It is essential that such criteria be accessible to and understood by the entities to which they apply. Accordingly, the Commission directs the ERO to submit to the Commission in an informational filing, in addition to regional criteria, all utility and RTO/ISO differences in transmission planning criteria that are more stringent than those specified by the TPL group of Reliability Standards. We believe that this information will provide us, as well as the ERO and industry with an indication of the actual transmission practices utilized in the industry today. This should be used by the ERO in the Reliability Standards development process.

ii. Sensitivity studies and critical system conditions

1695. The Commission stated in the NOPR that it is not realistic to expect the ERO to develop Reliability Standards that anticipate every conceivable critical operating condition applicable to unknown future configurations for regions with various configurations and operating characteristics.[426] The practical solution implemented by many in the industry is to perform sensitivity studies that define and provide documentation of the reliability impact on the system. The Commission therefore stated that it would be appropriate for planning entities to conduct sensitivity studies to ''bracket'' the range of probable outcomes. Thus, without having to anticipate ''every conceivable critical operating condition,'' planning entities will have a means to identify an appropriate range of critical operating conditions. Both staff and commenters on the Staff Preliminary Assessment noted that system conditions are as important as contingencies in evaluating the performance of present and future systems.

(a) Comments

1696. Most of the commenters agree with the Commission's proposal on sensitivity studies to determine critical

[426] NOPR at P 1047.

system conditions. These include FirstEnergy, TVA, MidAmerican, Entergy and SDG&E. However, a few commenters, including EEI, APPA, MISO and Northern Indiana, take the view that such a requirement is unnecessary and overly prescriptive.

1697. FirstEnergy states that it is appropriate for the Commission to require sensitivity analyses, because assessing multiple sensitivities against a set of system contingencies is prudent system planning.

1698. TVA agrees that an appropriate range of critical operating conditions that will ''stress'' the Bulk-Power System needs to be identified for use in transmission planning. It states that sensitivity studies should be performed and historic data analyzed to determine the most probable range of operating conditions that will stress the Bulk-Power System.

1699. MidAmerican believes that the proposal to require sensitivity studies to ''bracket'' the range of probable outcomes and determine critical system conditions is reasonable. It states that, while critical conditions may be determined in a similar manner for the different TPL Reliability Standards, different critical conditions are pertinent to each Reliability Standard. For example, thermal overloads occur under peak load conditions and dynamic instability occur under light load conditions.

1700. Entergy does not object to an assessment of critical system conditions using the factors identified in the NOPR,[427] but it contends that the Commission's guidance is problematic to the extent that it may require constructing facilities to address potential constraints identified through these assessments. Entergy states that such construction may not create a desirable result and may instead threaten reliability. For example, assessing a system using alternative generation dispatch and transaction patterns could bias a transmission provider in favor of transmission plans that benefit a specific generator or set of generators.

1701. SDG&E sees the Commission's treatment of sensitivity studies and critical system conditions as requiring transmission planning entities to exercise judgment in determining the scope, content and number of their sensitivity studies so that they are appropriate given unique system characteristics and reasonably anticipated contingencies. SDG&E state that this guidance is welcome and should be reflected in future Requirements.

1702. MISO agrees that planning entities should have a process to identify appropriate critical system conditions for planning purposes. However, it does not believe that the Reliability Standard needs to be prescriptive in terms of the specific sensitivities that should be evaluated. If an entity's approach to selecting the critical planning conditions is appropriate, sensitivities to variations from these conditions are unnecessary. MISO and Northern Indiana state that requiring sensitivities in planning studies as a mandatory standard practice could result in unnecessary additional analysis that could overwhelm the planning process and detract from more appropriate focused analysis and evaluation of solutions.

1703. EEI and APPA state that the Commission's proposal on sensitivity studies would add an unnecessarily redundant process that ignores the totality of the studies contained in study libraries that inform planners' decisions. The historical libraries of system studies provide a strong base for selecting critical transmission system conditions. EEI believes that the knowledge and experience of planners who have conducted these studies provides reliable guidance and that a new array of sensitivity analyses would offer no additional benefit over existing practices.

1704. Regarding specific variables to be included in sensitivity studies, EEI and APPA note that load power factors, controllable loads and DSM at specific locations and outages of reactive devices have much more to do with distribution operations planning than long-term system planning. They state that while transmission system planners will study a broad range of combinations of substation loadings, system configurations and resource availabilities over the planning horizon, changes in the variables of the sort identified by the Commission have very little influence on the long-term study outcomes except for the loss of load that could occur under extreme circumstances. MISO believes that transmission reactive power devices should be treated like any other transmission facility and included in the required contingency analysis. The current Reliability Standards are not explicit in this regard, and MISO agrees that this would be an appropriate clarification. It believes that power factor sensitivity studies are best suited for operational planning studies rather than long-term planning since corrective actions have relatively short lead times. In regard to alternative dispatch scenarios, MISO states that if a variation from the expected dispatch leads to unacceptable performance, it becomes an economic planning question, rather than a planning standard issue, whether expansion should be undertaken or whether the dispatch becomes a congestion cost.

(b) Commission Determination

1705. In response to Entergy's comments, the Commission reiterates the statement from the NOPR[428] that the results of the sensitivity studies would be used to document the selection of critical system conditions and study years used in assessing system conditions. The Commission notes that it is not the purpose of sensitivity studies to identify remedial actions, but, as stated in the NOPR, if different scenarios that lead to criteria violations are probable they require mitigation plans.[429] Entergy goes on to state that constructing facilities, the need for which is determined through sensitivity studies, may not create a desirable result, in that they may bias transmission plans towards a specific generator or set of generators and as a result may threaten reliability. The Commission disagrees that constructing well-planned facilities may threaten reliability. The planning process should anticipate any inter-regional impacts, and the net result should be higher local and inter-regional reliability. In any case, we are not requiring the construction of additional facilities.

1706. MISO, EEI, APPA and others question the value of sensitivity studies and their role in mandatory Reliability Standards given the knowledge and experience of planners and the historical library of system studies. The Commission notes that while specificity was not required in the regime of voluntary standards, it is required in a regime of mandatory Reliability Standards to ensure consistency in system assessment and provide clear and measurable requirements. Further, as stated in the NOPR[430] and concurred with by commenters to the Staff Preliminary Assessment, system conditions are as important as contingencies in evaluating the performance of present and future systems. Indeed, Table 1 lists the contingencies to be evaluated, but there is no corresponding requirement for selecting critical system conditions.

1707. The Commission believes it is important to clarify the type of analysis

[427] *Id.* at P 1061.

[428] *Id.* at P 1061.

[429] *Id.* at n 324.

[430] *Id.* at P 1046.

required in determining critical system conditions, which is the intent of the directed modifications on sensitivity studies. The Commission proposed in the NOPR a range of variables to be included in sensitivity studies, specifically: firm transfers, demand levels, existing and planned facilities, reactive power resources, control devices, load power factors, generation retirements, generation dispatch, transaction patterns, controllable loads, DSM and transmission outages including outages of reactive power devices.[431] The Commission also stated that it is not precluding other approaches to defining and documenting critical system conditions that have proven to be effective. The Commission also notes that in analyzing contingencies as part of Requirement R1.3.1 in Reliability Standards TPL–002–0 through TPL–004–0, not all contingencies need be assessed for every system element but only those that would produce the more severe reliability impacts with documentation of selection rationale. The same applies to the range of variables specified for sensitivity studies. The Commission expects that the full range of variables will be considered, but only those deemed to be significant need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

iii. Element-Based vs. Event-Based Contingencies

1708. The Commission stated in the NOPR that planning Reliability Standards must influence system design and not the other way around.[432] To achieve this objective, planning Reliability Standards should promote system designs that result in the minimum set of elements being removed from service for ''unanticipated failures of system elements.'' [433] The NOPR goes on to say that the Commission believes that the simulations used in planning assessments should faithfully duplicate what will happen in the actual power system and not a generic listing of outages. The Bulk-Power System also must be operated, and planned to be operated, within a number of conditions after a contingency or cyber event. The contingency can be a sudden disturbance or an unanticipated failure of any system element. If a specific portion of the system has been designed such that the response to a failure results in multiple lines, transformers, generators, circuit breakers, etc., being removed from service, the Commission proposed that this is what should be simulated.[434]

(a) Comments

1709. National Grid, MidAmerican and SDG&E support the principles set forth in the NOPR. National Grid states that event-based planning is a more robust form of contingency analysis than element-based planning because the former focuses on contingencies regardless of how many elements may be affected while the latter focuses on losses of specific elements that may not have a direct relationship to the severity of the impact on or risks to reliability. As such it supports the Commission's statement that ''simulations should faithfully duplicate what will happen in the actual power system and not a generic listing of outages.'' [435]

1710. MidAmerican states that it supports the Commission's proposal to interpret a ''single contingency'' to include all elements of the system, irrespective of their number, that go out of service in response to failure of a single element, as it has historically performed this analysis as a part of normal planning in the interest of reliability. MidAmerican is concerned, however, that this proposal may be too restrictive for system planning, particularly with regard to the double contingencies of Category C. It states that if a multi-element single contingency occurs first, as part of system adjustment, the reliability coordinator or transmission operator will switch back the unfaulted elements to service prior to the next contingency. Therefore this N–1–1 contingency at its worst will consist of a single element outage followed by a multi-element outage. Therefore MidAmerican states that the extent of a multiple-element single contingency is better determined through coordinated efforts of neighboring systems in conjunction with the planning authority and reliability coordinator.

1711. SDG&E agrees that further modifications to the TPL Reliability Standards should be guided by the NOPR's directive that simulations should faithfully duplicate what will happen in the actual power system and not a generic listing of outages. However, it states that the Commission should provide further guidance in defining an event so that planning studies can assess electrical system contingencies consistently and numerically. A simulation that faithfully duplicates reasonably expected scenarios will necessarily involve the transmission planner's sound engineering judgment and knowledge of elements that would be expected to be removed from service during the contingency. SDG&E states that the updated TPL Reliability Standard should reflect and implement these concerns.

1712. EEI believes the planning Reliability Standards and practices clearly reflect the language in FPA section 215 regarding ''element based'' planning. Planners study single contingency and multiple contingency events covering a broad range of system elements and not a list of generic outages.

1713. TANC recommends that the Commission direct that transmission planning in the West be based on probability of an event occurring and the severity of the consequences, rather than on a deterministic approach that uses single and multiple contingency categories as exemplified by Table 1. It states that WECC has assessed the probability of an event occurring for each category and assigned probabilities accordingly. TANC states that to be more cost effective and efficient, investments to remedy a problem should be based on a combination of the probability of the occurrence of the event and the severity of the associated consequences.

1714. In response to the Commission's request in the NOPR for comment on whether planning for cyber security events should be addressed in the planning Reliability Standards or in the Critical Infrastructure Protection (CIP) Reliability Standards,[436] MidAmerican, EEI, APPA, ISO–NE and SoCal Edison state they believe that events requiring study under the CIP Reliability Standards should be included in that specialized forum rather than the TPL Reliability Standards. Such events are identified using approaches provided for in the CIP Reliability Standards. Therefore the best place to explore those events and determine their impacts using the full background of the information about the events is the CIP Reliability Standards, although some of these events will require

[431] *Id.* at P 1047.

[432] *Id.* at P 1049.

[433] Section 215(a) of the FPA defines ''Reliable Operation'' as ''operating the elements of the Bulk-Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of sudden disturbance, including a Cybersecurity Incident, *or unanticipated failure of system elements*'' (emphasis added).

[434] With respect to failure, the element includes a single transmission line, transformer, generator or single pole of a DC line.

[435] NOPR at P 1049.

[436] *Id.* at P 1050.

implementation of elements from other Reliability Standards.

1715. National Grid and International Transmission take the view that cyber security incidents are no different than other events that remove single or multiple elements from service at a single time and require analysis of system impacts. Planning assessment for cyber security incidents therefore is most appropriately addressed in the TPL Reliability Standards. International Transmission states that although Table 1 of the TPL Reliability Standards does not list the initiating event, cyber security events could be included in the list of contingencies as an initiating event. National Grid cautions that provisions detailing specific cyber security protections should be addressed in CIP Reliability Standards, and emergency response procedures for response to cyber security events should be addressed in EOP Reliability Standards.

(b) Commission Determination

1716. Several commenters [437] agree with the Commission's statement in the NOPR [438] that ''simulations should faithfully duplicate what will happen in the actual power system and not a generic listing of outages.'' It follows that in simulating the failure of a single element, as required in Category B of TPL–002–0, all of the elements that are removed from service to isolate the single faulted element should be modeled in the simulation rather than restricting the simulation to just the single faulted element, as Table 1 of TPL–002–0 implies. As SDG&E notes, this will require the transmission planner's sound engineering judgment and knowledge of elements that would be expected to be removed from service during the single contingency. The Commission agrees with MidAmerican that for Category C contingencies of TPL–003–0, the worst N–1–1 contingency would be a single element outage followed by a multiple element outage, provided that following the first N–1 contingency, capability exists to switch the unfaulted elements back into service promptly, *i.e.*, within 30 minutes, as part of the adjustments that the Reliability Standard allows.

1717. SDG&E agrees that simulations should faithfully duplicate what will happen in the actual power system and not a generic listing of outages, but it seeks Commission guidance on how an event should be defined. In the Commission's view, a single contingency consists of a failure of a single element that faithfully duplicates what will happen in the actual system.[439] Such an approach is necessary to ensure that planning will produce results that will enhance the reliability of that system. Thus, if the system is designed such that failure of a single element removes from service multiple elements in order to isolate the faulted element, then that is what should be simulated to assess system performance. Accordingly, the Commission directs the ERO to submit modifications to Category B of Table 1 consistent with this approach. Entities whose systems may have been planned and designed on the basis of a different approach to single contingencies should work with the ERO in developing plans to transition to this approach.

1718. The Commission disagrees with EEI that the planning Reliability Standards and practices clearly reflect the language in FPA section 215 regarding ''element based'' planning. Section 215(a) of the FPA defines ''Reliable Operation'' as ''operating the elements of the Bulk-Power System'' within certain limits so that ''instability, uncontrolled separation or cascading failures of that system will not occur as a result of sudden disturbances, including a cyber security incident, or unanticipated failure of system elements.'' This definition specifies an ultimate goal and does not dictate any specific type of planning. The approach to a single contingency the Commission has set forth above ensures that transmission planners analyze contingencies based on the actual number of elements that would be removed from service in the actual power system for ''an unanticipated failure of system elements,'' rather than simulating only the limited number of outages listed in Table 1 of the TPL Reliability Standards. In short, the Commission's approach speaks directly to the problem that the statute requires be addressed.

1719. In response to TANC's proposal that the Commission direct that probabilistic approaches to transmission planning be adopted in the West, the Commission notes that proposals of this type should be submitted to the ERO for approval as a regional difference. If such a proposal is developed for the Western Interconnection, to assist the ERO and the Commission in its assessment of such a proposal, we encourage WECC to also submit operating information that quantifies the level of actual performance that has been achieved with the present deterministic planning approach. Such performance metrics would assist us in determining whether a probabilistic approach would result in equivalent or higher levels of Reliable Operation than currently achieved.

1720. In response to the comments received on how best to address planning for cyber security events, it is clear that the nature of risks as well as the contingencies and measures needed to overcome them are best addressed in the CIP Reliability Standards because this forum has the specialized knowledge to deal with cyber security matters. However, the system impacts of cyber security events are best addressed in the TPL group of Reliability Standards, particularly TPL–004–0, alongside other similar common mode failures. Emergency plans and restoration procedures to deal with cyber security events are best addressed by the EOP Reliability Standards because these Reliability Standards deal with emergency plans and restoration procedures. The Commission directs the ERO to consider appropriate revisions to the Reliability Standards through its Reliability Standards development process to address these matters.

iv. Spare Equipment Strategy

1721. The Commission stated in the NOPR that while Reliability Standards TPL–002 through TPL–004 require consideration of planned outages at those demand levels for which planned outages are performed, they do not address situations where critical equipment, such as a transformer or phase angle regulator, may be unavailable for a prolonged period. Including such a requirement would ensure the coordination of contingency plans, including the entity's spare equipment strategy, to return facilities to service in a timely manner for reliability. The Commission therefore proposed that the Reliability Standards be modified to include a new requirement to assess the reliability impact of an entity's existing spare equipment strategy.

(a) Comments

1722. SDG&E states that it generally supports a new requirement that would include assessing the reliability impact of an entity's spare equipment strategy, but several key features of this requirement need clear and thorough definition. For example, the requirement should provide an industry-developed finite list of ''critical items,'' and the meaning of ''impact IROL'' would need further clarification. SDG&E submits that, absent a careful delineation of the requirement and its

[437] National Grid, MidAmerican and SDG&E.

[438] NOPR at P 1049.

[439] A ''single element'' means a transmission line, a transformer, a generator or a single pole of a DC line.

terms, this proposed modification will not enhance system reliability.

1723. MidAmerican, LPPC, EEI, APPA and SoCal Edison state that they understand the Commission's concern about spare equipment planning and acquisition strategy. However, MidAmerican and LPPC note that typically spare equipment strategy is of more concern in operating studies than planning studies. MidAmerican states that most equipment can be installed in a year or less even if it is not on hand. It maintains that it may be appropriate to add this requirement to the TPL Reliability Standards because scarcity of new equipment due to recent disasters has led to longer lead times. LPPC cautions the Commission that associating spare equipment strategy with the planning Reliability Standards could lead to Reliability Standards that overstep the limits of FPA section 215(i)(2) through proposing a Reliability Standard that would, indirectly, come close to authorizing the ERO to order the construction of transmission capacity. LPPC states that it is unclear how to separate: (1) Requiring a utility to assess its spare equipment strategy; (2) requiring a utility to have spares on hand to meet anticipated reliability needs and (3) requiring a utility to use spare equipment to meet the reliability needs.

1724. EEI, APPA and SoCal Edison question the need to address this issue in the context of a Reliability Standard. EEI states that, where delivery delay could occur for long lead time equipment such as transformers, the existing Reliability Standards provide for study of the full range of single and multiple-event contingencies with that piece of equipment modeled off-line. According to EEI, the Commission's general concern regarding the current policies and practices related to equipment acquisition can be addressed in the NERC forum without revising the Reliability Standards. This forum also will account for the need to protect information on critical infrastructure facilities.

(b) Commission Determination

1725. Several commenters stated that they understand the Commission's concern about requiring a reliability impact assessment of an entity's spare equipment strategy, but they question the need to address this issue in the Reliability Standards in general and the transmission planning Reliability Standards in particular. The Commission disagrees with EEI that the existing Reliability Standards provide for situations that cover the delivery of long lead time equipment, such as transformers, by requiring a full range of single and multiple contingency studies with that equipment modeled off-line. TPL–002–0 and TPL–003–0 currently state explicitly in Requirement R1.3.12 that the assessments shall include planned outages of bulk electric equipment at those demand levels for which planned (including maintenance) outages are performed. However, equipment such as transformers may not be available for service for a year or more and therefore their unavailability cannot be scheduled when system conditions permit.

1726. The current Reliability Standards do not require assessment of the reliability impacts that result from not having this long lead time equipment available under those system conditions likely to be experienced during the course of the year when the system is heavily stressed. Clearly the consideration of planned outages is inextricably linked with spare equipment strategy. Thus, if an entity's spare equipment strategy for the permanent loss of a transformer is to use a ''hot spare'' or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions. However, if the spare equipment strategy entails acquisition of a replacement transformer that has a one-year or longer lead time, then the outage of the transformer must be assessed under the most stressed system conditions likely to be experienced. Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy.

1727. LPPC questions whether the Commission's proposal oversteps the limits of FPA section 215(i)(2) because assessing the impact on reliability of an entity's decision concerning spare equipment could force an entity to construct transmission capability. FPA section 215(i)(2) prohibits the ERO and the Commission from ordering the construction of ''additional'' transmission capacity. A requirement to assess the reliability impacts of an entity's spare equipment strategy is no different than a requirement to assess the reliability impacts of any number of contingencies. Even if an entity was forced to conclude that its spare strategy was inadequate, rectifying the problem would not require that the entity construct ''additional'' transmission capacity, only that it possess adequate spares, or take other appropriate action, to ensure the reliable operation of its system. In short, while FPA section 215(i)(2) precludes ordering expansion of transmission or generation capacity, section 215 clearly authorizes requiring entities to take appropriate steps to ensure that their existing capacity operates reliably.

1728. With regard to SDG&E's suggestion to clarify specific elements of this Reliability Standard, we direct the ERO to consider such suggestions in its Reliability Standards development process.

v. Resource Information for Planning

1729. The Commission in the NOPR requested comments on whether transmission planners and planning authorities are currently able to obtain and validate resource information on new generation and retirements for assessments over the ten year planning horizon. Further, if transmission planners and planning authorities currently experience difficulty obtaining this information, the Commission asked how this potential information gap should be addressed.[440]

(a) Comments

1730. The Commission noted in the NOPR that transmission planning requires information on forecasted loads and probable generation plans to supply those loads.[441] While the MOD Reliability Standards require information on forecasted loads, energy, interruptible loads and direct control load management over the next ten years, there is no requirement to inform transmission planners and planning authorities of new or retiring generation resources. The Commission sought comments on whether transmission planners and planning authorities are currently able to obtain and validate resource information on new generation and retirements for assessments over the ten year planning horizon and if not, how this potential gap should be addressed.

1731. NERC stated that it and the regional reliability organizations have generally not had problems obtaining the data and information required for reliability assessments. NERC believes that given its authority and responsibility as the ERO, it will be successful in obtaining all the data and information it needs to conduct reliability assessments without the need to include these requirements in Reliability Standards. In the event that it and the regional reliability organizations are unsuccessful in obtaining such data and information,

[440] NOPR at P 1060.

[441] *Id.*

the ERO will turn to the Commission for assistance.

1732. ISO–NE states that as the planning authority it obtains resource plans for additions, capacity changes, deactivations and retirements for a ten year planning horizon. Although these plans cannot be expected to occur exactly as projected, they serve as useful information in projecting needs for new resources or new or upgraded transmission facilities. As the administrator of wholesale electric markets, ISO–NE relies on the development of robust market rules accompanied by a regulated transmission planning process to achieve its goal of encouraging the availability of sufficient resources. ISO–NE states that planning for the introduction and retirement of specific resources ten years in advance not only is unnecessary, it is inconsistent with relying on markets to determine the most efficient allocation of resources to meet system needs.

1733. FirstEnergy and SoCal Edison state that currently they are able to obtain information regarding new generation from publicly available information and from the generator interconnection queue. Typically, a generation application that is in the interconnection agreement phase is considered for transmission planning studies. New generation has a longer lead time, and thus information on it may be available sooner than information about retirements, which have a much shorter lead time before they are announced. FirstEnergy states that despite the unpredictability of such information, assessments can be conducted using assumptions of new generation and retirements, and the results should recognize that the inputs were based on reasonably foreseeable conditions.

1734. In contrast, CAISO, National Grid and Northern Indiana state that obtaining resource information has been a challenge given that the Reliability Standards impose no obligation on generation owners to provide information to planning authorities and transmission service providers about new and retiring generation. Northern Indiana states that this issue is among the greatest challenges for its transmission planners. Because transmission planning is focused on matching the source to the sink, having the sources unknown, in the case of future generation, creates a weakness in the entire transmission planning process. Northern Indiana contends that weakness will be difficult to eliminate because information about siting of future generation units is considered commercially sensitive information. This lack of information makes it difficult for transmission planners to reflect accurately the amount and location of new generation in their transmission studies. CAISO agrees that there is a gap in its ability to obtain this information particularly from adjacent balancing authorities. CAISO suggests that to bridge this gap, generator owners and operators should be required to provide data about new and retiring generation to their planning authorities and that the planning authorities be required to share this information with neighboring balancing authorities, subject to appropriate non-disclosure agreements. CAISO notes that there currently exists no centralized database for the collection and dissemination of this information within the Western Interconnection.

1735. National Grid states that forward capacity markets and the generation interconnection queue provide some understanding about new generation but only for five to seven years, even though transmission planning horizons are considerably longer. National Grid and Northern Indiana contend that it may be reasonable to conclude that certain areas are prime locations for new resources, particularly inexpensive and renewable resources that are dependent on ''non-transportable'' fuel supplies. National Grid states that the Commission should embrace efforts of transmission planners to facilitate new generation entry when such initiatives are expected to increase customer access to inexpensive, renewable and diverse sources of supply.

1736. Entergy believes that from a transmission provider's point of view it would be desirable to have LSEs provide ten or even five-year resource forecasts. Entergy recognizes that such a requirement may not be practical when LSEs depend significantly on short-term purchases due to the abundance of independent power producers or in areas that have an locational marginal pricing-like market structure. MISO states that its experience suggests that LSEs do not identify new generation resources except in very general terms past the second or third year. In most cases LSEs show future capacity requirements served from generic base load and peaking power resources or from potential contract purchases with no information on location. This increases the difficulty of accurate long-range transmission planning studies.

1737. National Grid states that it is also vitally important to acknowledge that generation retirements may pose a greater threat to reliability in some areas of the country than the slow down of new generation. Because required notice periods for retirements may be as little as ninety days in some areas, it is imperative that transmission planners use a robust statistical approach to identify vulnerable sources of generation and conduct such modeling as an integral part of the transmission planning process.

1738. MISO states that planning assumptions around generation retirements are particularly difficult because such assumptions are driven by complex economic factors that may or may not prevail. While MISO has the tools to project what unit may be more likely to retire than others, it contends that the preferred approach is to have in place tariff provisions that require suppliers to announce retirement intentions six months in advance of the retirement. This permits reliability studies to be performed with certainty and corrective actions to be implemented that could include placing the unit on contract to continue operations until appropriate operating measures or system expansions can be made.

1739. SoCal Edison states that business decisions by generator owners to retire or mothball units are outside of SoCal Edison's control, and generally SoCal Edison does not receive this information in a timely manner for transmission planning studies.

1740. National Grid urges the Commission to support longer planning horizons. It states that in many respects, the ten year planning horizon may be too short a time frame for assessing transmission needs, particularly with regard to long distance extra high voltage facilities that pose considerable siting and permitting challenges. Establishing planning horizons that are shorter than transmission construction lead times may create gaps where the identification of a reliability need to which transmission may be the best solution occurs too late to head off the identified reliability violation. National Grid states that PJM is establishing a fifteen year planning horizon that will accommodate large-scale projects that are needed for reliability and to support regional transactions.

1741. MISO and International Transmission note that while it is important for planners to have quality information on available resources, the enabling legislation for the ERO specifically excludes authority regarding resource adequacy. MISO states it is not certain how far the Reliability Standards can go. International Transmission states that, in the absence of a standard on resource

adequacy, transmission service providers must use their judgment on potential new generation or retirements to create base cases and plan the system accordingly.

1742. Reliant states that, while section 215 of the FPA requires the ERO to develop Reliability Standards that provide an adequate level of Bulk-Power System reliability, the proposed Reliability Standards surprisingly lack any substantive consideration of planning reserve obligations to ensure capacity available to meet the needs of a reliable system. Reliant proposes that each regional reliability organization develop and enforce its own minimum planning reserve margin. Such a program would be critical to the development of new generation, demand response and distributed generation resources and allow each region to retain its own autonomy in developing its own resource adequacy standards.

1743. Process Electricity Committee supports long-term planning as a vital part of any economic and thorough set of Reliability Standards. However, it is concerned that transmission service providers who are also market participants will have an incentive to exploit commercially sensitive data on generation plans to the disadvantage of other competing suppliers. Process Electricity Committee asks the Commission to clarify that transmission planners may not use the Reliability Standard to obtain and exploit such information, and it urges the Commission to take all appropriate measures to guard against such abuse.

(b) Commission Determination

1744. Several commenters addressed separately the availability of information on new generation resources and generation retirements, given that these have very different lead times. NERC, ISO–NE and others appear to be able to acquire the resource information they need on new resources and retirements for reliability assessments. Others, such as National Grid and MISO, have had difficulty in obtaining this information in a timely manner, particularly as it relates to generation retirements.

1745. The Commission disagrees with ISO–NE's statement that planning for the introduction of resources ten years in advance is not necessary. The existing Reliability Standard requires that the planning horizon must take into account the lead times for siting and permitting of new long-distance transmission lines and other solutions that can exceed ten years. In short, the need for long-term planning has already been widely recognized. The Commission agrees with National Grid that establishing planning horizons that are shorter than transmission lead times may create gaps where the identification of a reliability need to which transmission may be the best solution occurs too late to avert the identified reliability violation. Indeed, this point is supported by the fact that PJM is establishing a fifteen year planning horizon.[442]

1746. In the absence of information about future generation resources required for transmission planning the Commission notes that entities conduct assessments using assumptions based on the knowledge that certain areas are prime locations for new resources, particularly those resources that use non-transportable fuels. National Grid states that generation retirements may pose a greater threat to reliability in some areas than the slowdown of new generation construction. As a result, it states that it is imperative that transmission planners use robust statistical approaches to identify vulnerable sources of generation and conduct such modeling as an integral part of the transmission planning process. The Commission understands this as a further endorsement of its proposal to require a full range of sensitivity studies discussed above.

1747. MISO, International Transmission and Reliant raise important issues about the absence of a Reliability Standard on resource adequacy. Reliant points out the inconsistency between the statutory requirement to provide an adequate level of Bulk-Power System reliability and the lack of any substantive consideration of planning reserve obligations to ensure capacity is available to meet the needs of a reliable system. In the same vein, the Commission notes that Requirement R7 of TOP–002–0 requires each balancing authority to plan to meet capacity and energy reserve requirements in the operating time-frame but that there is no explicit corresponding consideration required of generation reserves in the planning time-frame.

1748. Section 215(a)(3) of the FPA makes clear that enforceable Reliability Standards may not address requirements to enlarge facilities or construct new generation capacity. We have noted that when a state or appropriate jurisdictional entity has such a requirement, it should be included in transmission planning analysis. Resource adequacy levels are set to achieve a number of goals, one of which is system reliability. Our jurisdiction is to approve and enforce Reliability Standards that provide for an adequate level of reliability for the Bulk-Power System. The TPL group of Reliability Standards includes load growth, changes in the transmission topology, existing generation, generation retirements, and confirmed new generation as inputs to the analyses. When an entity does not meet a reliability criterion, including the inability of generation to be deliverable to load, mitigation plans are required. Although the Commission anticipates that some of those mitigation plans may include new generation, we do not require this.

1749. Some entities have proposed possible solutions to address the gap of inadequate and unreliable resource information for long-term planning as required by the TPL group of Reliability Standards. CAISO suggests that generator owners and operators be required to provide data on new generation and retirements to their planning authorities. Entergy proposes requiring LSEs to provide this information, but recognizes that this approach has its limitations. MISO contends the preferred approach to retirements is to have in place tariff provisions that require suppliers to announce retirement intentions six months in advance of retirements. Process Electricity Committee is concerned about the implications of sharing non-public transmission or customer information which could then be exploited to the disadvantage of competing suppliers. The Commission's Standards of Conduct addresses the sharing of such information and generally prohibits the sharing of commercially sensitive information between the transmission organization and affiliated merchant functions.[443] In response to Process Electricity Committee, the Commission will continue to enforce the information sharing prohibition in the Standards of Conduct.

1750. The responses to the Commission's inquiry on these matters are helpful. The comments further point out the importance of conducting a wider range of sensitivity studies on generation scenarios. However, the Commission is not directing at this time any modifications to address the Commission's concerns.

[442] *See http://www.pjm.com/contributions/pjm-manuals/manuals.html.*

[443] *See* Order No. 2004.

vi. Sharing of Information With Neighboring Systems

1751. In the NOPR, the Commission stated that, because neighboring systems may be adversely impacted, such systems should be involved in determining and reviewing system conditions and contingencies to be assessed in connection with Requirement R1.3 of TPL–001–0 to TPL–004–0.[444]

(a) Comments

1752. EEI, APPA, FirstEnergy, ERCOT and SDG&E support or acknowledge the value of sharing of various kinds of planning information with neighboring systems. FirstEnergy states that the proposed requirement that system conditions and contingencies assessed be shared and reviewed by neighboring systems will improve communications with interconnected companies. This process was established among former ECAR companies through the ''ECAR Peer Review Process,'' and FirstEnergy recommends that regional reliability organizations be encouraged to establish a similar process going forward. EEI and APPA state that sharing of various kinds of planning information, including expected generation additions and retirements, planned outages, demand forecasts and estimates of firm transfers will go a long way to improving the quality and consistency of planning study efforts. However, it is not clear to EEI whether a formal Reliability Standard would be the most effective approach. An alternative could be to request that NERC oversee an informal process to explore alternatives and report back to the Commission by a specific date. Although ERCOT states that this proposal is a sensible recommendation, it also states that it would not be appropriate for ERCOT since the transmission service provided there is not subject to interruption by the ISO, and outbound flows are also not interrupted if there is a shortage of capacity.

1753. SDG&E notes that under the auspices of the CAISO it regularly convenes stakeholder meetings with the general public, neighboring utilities, generator owners, regulators and the CAISO. In these meetings, SDG&E reviews the grid assessment process and receives comments from participants about all aspects of its process. As a member of WECC, SDG&E states that it also holds meetings to discuss inter-area projects that SDG&E has proposed to construct. This review group consists of neighboring utilities, generator owners and other stakeholders who are members of WECC. Similarly, SDG&E maintains that it participates in other California-based utility review groups. SDG&E finds that these existing processes provide ample opportunities for regular sharing of relevant information with neighboring transmission planning entities. It thus recommends that the Reliability Standards development process take into account existing forums for apprising neighboring utilities of current and anticipated transmission planning issues and projects. If the Commission believes additional communications are needed, SDG&E strongly recommends that the Commission, through NERC or the applicable Regional Entity, specify in greater detail the nature and periodicity of the information to be shared pursuant to the TPL Reliability Standards.

1754. SoCal Edison states that TPL–001–0 is for systems operating under normal conditions, and as such there should not be a need for any review by neighboring systems.

(b) Commission Determination

1755. Most commenters agree with the Commission's proposal that neighboring systems be involved in a peer review of system assessments in connection with Requirement R1.3 of TPL–001–0 through TPL–004–0. Given that neighboring systems assessments by one entity may identify possible interdependent or adverse impacts on its neighboring systems, this peer review will provide an early opportunity to provide input and coordinate plans. The Commission therefore disagrees with SoCal Edison's view that there is no need for any review by neighboring systems for TPL–001–0. For example, the planning authorities needs to be consistent in the line flow values that they use.

1756. While supporting the concept of a peer review, EEI questions whether making this a Requirement in a Reliability Standard is the most effective approach or whether NERC should explore alternatives and report to the Commission by a specific date. The Commission sees no reason why peer reviews should not be part of a Reliability Standard since TPL–001–0 through TPL–004–0 already include in Requirement R1.3 a review of assessments by the associated regional reliability organization. The Commission understands that some regions include peer review as part of their procedures. Accordingly, to ensure that neighboring systems are not adversely affected and to provide an early opportunity for input and coordination of plans, the Commission directs the ERO to include these modifications to the Reliability Standard through its Reliability Standards development process to provide for the appropriate sharing of information with neighboring systems.

1757. The Commission has taken action on its OATT reform initiative in Order No. 890. In that order, the Commission encourages the formation of regional planning processes and economic planning studies.[445] Sharing of information and peer review are the first steps in a regional planning process. The Commission provides guidance and direction on these subjects in our discussion of Reliability Standard TPL–005–0.

b. System Performance Under Normal (No Contingency) Conditions (TPL–001–0)

1758. Reliability Standard TPL–001–0 deals with planning related to system performance under normal conditions, *i.e.*, a situation where no system contingency or no unexpected failure or outage of a system component has occurred.[446] The Reliability Standard seeks to ensure that the Bulk-Power System is planned to meet the system performance requirements under these normal conditions by requiring the transmission planner and the planning authority to evaluate their transmission system annually and document the ability of that system to meet the performance requirements established in the Reliability Standard under conditions where no system contingencies are present.[447] Meeting these requirements means two things. First, when all system facilities are in service and normal operating procedures are in effect, the system can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services at all demand levels over the range of forecast system demands. Secondly, the system remains stable and within the applicable ratings for thermal and voltage limits, no loss of demand or curtailed firm transfers occurs, and no cascading outages occur. TPL–001–0 applies both to near-term and longer-term planning horizons.

1759. The Requirements of TPL–001–0 specify that the planning authority and transmission planner must

[444] NOPR at P 1063.

[445] Order No. 890 at P 526, 542.

[446] The NERC Glossary defines a ''contingency'' as ''[t]he unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.'' NERC Glossary at 3.

[447] The performance requirements are set forth in Category A of Table I of the Reliability Standard.

demonstrate through a valid assessment that the Reliability Standard's system performance requirements can be met. The assessment must be supported by a current or past study and/or system simulation testing that addresses various categories of conditions to be simulated as set forth in the Reliability Standard to verify system performance under normal conditions. When system simulations indicate that the system cannot meet the performance requirements set forth in the Reliability Standard, a documented plan to achieve system performance requirements must be prepared. The specific study elements selected from each of the categories for assessments are subject to approval by the associated regional reliability organization.

1760. The Commission proposed in the NOPR to approve Reliability Standard TPL–001–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL–001–0 that: (1) Requires that critical system conditions be determined by conducting sensitivity studies; (2) requires that system conditions and contingencies assessed be reviewed by neighboring systems; (3) modifies Requirement R1.3 to substitute the reference to regional reliability organization with Regional Entity; (4) requires consideration of planned outages of critical equipment; and (5) modifies footnote (a) of Table 1 to not apply emergency ratings to compare stresses on the system under normal conditions as recommended by the Transmission Issues Subcommittee of the NERC Planning Committee [448] and require that normal facility ratings be in accordance with Reliability Standard FAC–008–1 and that normal voltages be in accordance with Reliability Standard VAR–001–1.[449]

i. Comments

1761. APPA agrees with the Commission that TPL–001–0 is sufficient for approval as a mandatory and enforceable standard.

1762. MidAmerican and others generally support the Commission's proposal to improve TPL–001–0 but caution that: (1) Planned outages should only be considered at load levels and conditions under which they commonly occur and (2) emergency ratings should recognize the varying timeframes of overloads that result from various contingency events. Further, MidAmerican states that, while it is appropriate that planning margins for normal voltages be calculated in accordance with VAR–001–1 as proposed by the Commission, it would be better if the proposed modification provided that voltage criteria do not conflict with VAR–001–1. Northern Indiana agrees with the Commission's position regarding consideration of planned outages and states that it considers them currently in its transmission planning studies. International Transmission states that both planned outages of critical equipment and the extended forced outages of similar equipment should be considered. FirstEnergy states that planned outages should be accounted for at load levels and conditions under which they commonly apply.

1763. Other commenters disagree that planned outages of critical equipment should be included in TPL–001–0.[450] They contend that the Reliability Standard has a very simple aim, namely, to examine whether a system can perform under normal system intact conditions, *i.e.,* when all elements are in service and operating as expected. The outages contemplated are appropriate for TPL–002–0 through TPL–004–0 where the planned outage could be a line outage caused by a maintenance project that extends into a period where the system is heavily loaded. SDG&E states that for near-term planned outages, the transmission planning entity should retain an appropriate amount of latitude to plan the outage's timing and details and to modify them as necessary. SDG&E comments that, for outages planned with a more distant horizon (one year or longer), this information can be accounted for in sensitivity analyses. SoCal Edison states that no information will be available about planned outages of critical equipment to be used for short-term (five years) or long-term (10 years) simulations. It may be possible to consider planned outages of critical equipment if there is a major project construction activity. If generators and transmission lines are out for scheduled maintenance during off-peak load conditions, then these outages should be considered.

1764. EEI supports the Commission's recommendation to modify footnote (a) in Table 1. International Transmission states that the footnotes in Table 1 are not footnotes but rather requirements for transmission system performance. These should be made requirements of the Reliability Standards so that they are more obvious and easier to monitor. APPA, LPPC and TANC recommend that changes to footnotes of Table 1 be subject to the Reliability Standards development process. They state that the footnotes have been extensively reviewed by technical experts at NERC for several years and currently represent a general consensus among these industry technical experts. Changes to the footnotes impact Table 1 and have a direct impact on the determination of the severity of consequences that were approved along with the original Reliability Standard. Therefore, the Commission should give due weight to the ERO and allow the Reliability Standards development process to resolve any existing ambiguities in the Table 1 footnotes.

ii. Commission Determination

1765. The Commission approves TPL–001–0 as a mandatory and enforceable Reliability Standard. In addition, we direct the ERO to develop modifications to TPL–001–0 through the Reliability Standards development process, as discussed below.

1766. In assessing system conditions, Requirement R1.3.1 of TPL–001–0 requires entities to cover ''critical system conditions and study years,'' as deemed appropriate by the entity performing the study. As stated in the NOPR, system conditions are as important as contingencies in evaluating the performance of present and future systems,[451] and yet TPL–001–0 does not specify the rationale for determining critical system conditions and study years. Consistent with our discussion of the issue above regarding sensitivity studies and critical system conditions, the Commission concludes that proposed modification (1), which requires that critical system conditions be determined by conducting sensitivity studies, is justified. Accordingly, we direct the ERO to modify the Reliability Standard to require that critical system conditions and study years be determined by conducting sensitivity studies with due consideration of the range of factors outlined above.

1767. Requirement R1.3 of TPL–001–0 states that the planning authority and transmission planner must provide studies and simulations to support its planning assessments, and that the specific elements selected for the study shall be acceptable to the associated regional reliability organization. Given that neighboring systems may be

[448] See NERC Transmission Issues Subcommittee Report: *Evaluation of Criteria, Methods and Practices Used in System Design, Planning and Analysis in Response to NERC Blackout Recommendation 13c.* Appendix B, November 28, 2005.

[449] NOPR at P 1065–67.

[450] *See, e.g.,* EEI, APPA, SDG&E, Entergy, SoCal Edison and TVA.

[451] NOPR at P 1046.

adversely affected, our goal is to ensure that they are involved in the determination and review of system assessments to permit an early opportunity to provide input and coordinate plans. We discussed above the issue of information sharing as it applies to the TPL group of Reliability Standards generally and, consistent with our conclusions there, we direct the ERO to modify TPL–001–0 to require a peer review of planning assessments with neighboring entities.

1768. The Commission received no comments on its proposal that Requirement R1.3 be modified to substitute the reference to the regional reliability organization with a reference to the Regional Entity. The Commission has explained the need for this modification above, and therefore it directs the ERO to modify Requirement R1.3 of TPL–001–0 to substitute the reference to the regional reliability organization with a reference to the Regional Entity.

1769. While some commenters support the consideration of planned outages at load levels for conditions under which they are performed, others disagree on the grounds that the goal of TPL–001–0 is to ensure that the Bulk-Power System can perform reliably when all elements are in service and operating as expected. The Commission notes that Reliability Standards TPL–002–0 through TPL–004–0 include consideration of planned outages, as initial system conditions, at load levels for conditions under which they are performed. Because these Reliability Standards, and not TPL–001–0, will govern the adequacy of the Bulk-Power System under planned outage conditions, the Commission will not adopt the NOPR proposal to require consideration of planned outages at load levels for conditions under which they are performed for Reliability Standard TPL–001–0. However, consistent with our discussion above on spare equipment strategy, the Commission directs a modification to this Reliability Standard to require assessments of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy. Thus, for example, if an entity's spare equipment strategy for the permanent loss of a transformer is to use a ''hot spare'' or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions. However, if the spare equipment strategy entails acquisition of a replacement transformer that has a one-year or longer lead time, then the outage of the transformer must be assessed under peak loading conditions likely to be experienced. This approach will ensure that system conditions are adequately assessed.

1770. While commenters generally agree with the Commission's proposal to modify footnote (a) of Table 1, they caution that any changes to the footnotes affect Table 1 and should be reviewed through NERC's Reliability Standards development process. International Transmission states that the footnotes in Table 1 are not footnotes but rather requirements for transmission system performance and therefore should be made Requirements in the Reliability Standard. The Commission agrees with International Transmission because this will promote clarity in and consistent application of the Reliability Standard. The Commission therefore directs the ERO to modify the Reliability Standard to address the concerns regarding footnote (a) of Table 1, including the applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other Reliability Standards. As with any modification to a Reliability Standard, modifications to TPL–001–0 should be developed through the ERO's Reliability Standards development process.

1771. Accordingly, the Commission approves Reliability Standard TPL–001–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL–001–0 through the Reliability Standards development process that: (1) Requires that critical system conditions and study years be determined by conducting sensitivity studies with due consideration of the range of factors outlined above; (2) requires a peer review of planning assessments with neighboring entities; (3) modifies Requirement R1.3 to substitute the reference to regional reliability organization with Regional Entity; (4) requires assessments of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy; and (5) address the concerns regarding footnote (a) of Table 1, including the applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other Reliability Standards and the concerns raised by International Transmission in regard to the footnotes in Table 1.

c. System Performance Following Loss of a Single Element (TPL–002–0)

1772. Reliability Standard TPL–002–0 addresses system planning related to performance under contingency conditions involving the failure of a single element with or without a fault, *i.e.*, the occurrence of an event such as a short circuit, a broken wire or an intermittent connection. The Reliability Standard seeks to ensure that the future Bulk-Power System is planned to meet the system performance requirements, with the loss of one element, by requiring that the transmission planner and planning authority annually evaluate and document the ability of the transmission system to meet the performance requirements where an event results in the loss of a single element.[452] Meeting these requirements means two things. First, it means that the system can be operated following the event to supply projected firm customer demands and projected firm (non-recallable reserved) transmission services at all demand levels over the range of forecast system demands. Second, it means that the system remains stable and within the applicable ratings for thermal and voltage limits, no loss of demand or curtailed firm transfers occurs, and no cascading outages occur.[453] The Reliability Standard applies both to near-term and longer-term planning horizons.

1773. TPL–002–0 specifies that the planning authority and transmission planner must demonstrate through a valid assessment that the Reliability Standard's system performance requirements can be met. The assessment must be supported by a current or past study and/or system simulation testing that addresses various categories of conditions to be simulated, as set forth in the Reliability Standard, to verify system performance under contingency conditions involving the failure of a single element with or without a fault. The Reliability Standard requires that planned outages of transmission equipment be considered for those demand levels for which planned outages are performed. When system simulations indicate that the system cannot meet the performance requirements stipulated in the Reliability Standard, a documented plan to achieve system performance requirements must be prepared. The specific study elements selected from each of the categories for assessments are subject to approval by the associated regional reliability organization.

1774. The Commission proposed in the NOPR to approve Reliability Standard TPL–002–0 as mandatory and

[452] The performance requirements are set forth in Category B of Table 1 of the Reliability Standard.

[453] Footnote b to Table 1 allows for the interruption of firm load for consequential load loss.

enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL–002–0 that: (1) Requires that critical system conditions be determined in the same manner as proposed for TPL–001–0; (2) requires the inclusion of the reliability impact of the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase ''permit operating steps necessary to maintain system control'' and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss.

i. Comments

1775. APPA agrees that TPL–002–0 is sufficient for approval as a mandatory and enforceable reliability standard.

1776. In response to the Commission's proposal [454] that NERC modify TPL–002–0, in part, because it does not address situations in which critical equipment may be unavailable for a prolonged period, Northern Indiana states that systems depicted in planning studies cannot possibly contain complete planned and forced outage schedules for the next ten years. For this reason TPL–003–0 deals with double contingencies, *i.e.*, contingencies that allow operator intervention after the first outage, and then capture system response to an additional outage. Operator intervention includes coordination of contingency plans and may impact strategies for spare equipment, particularly for critical equipment.

1777. EEI and MidAmerican support requiring all generators to ride through the same contingencies as required for wind generators. Constellation notes that while it supports the Commission's proposed modifications to TPL–002–0, an explicit requirement that all generators stay online during the same set of Category B and C events, as is required for wind generators, is too broad. Constellation requests that the Commission modify this requirement to recognize that NRC has specific requirements for how nuclear generation must respond to disturbances on the Bulk-Power System, and that those NRC rules should apply. Moreover, Constellation generally recommends that the Reliability Standards applied to nuclear generation should be consistent with NRC requirements and that NRC rules should control in the event of conflict.

1778. NRC notes that there appears to be significant variation in the interpretation of this Reliability Standard. It states that some of its licensees interpret the TPL–002–0 Reliability Standard to state that if a licensee is operating in an N–1 condition another single contingency does not need to be considered. NRC states that its interpretation has been that the N–1 condition is always analyzed from the conditions being experienced. They state that this Reliability Standard should be clarified and recommend specific revisions to Requirements R1.6, R2.1, R2.2 and Levels of Non-Compliance.

1779. Northern Indiana expresses concern about the statement in P 1062 of the NOPR that ''load models used in system studies have a significant impact on system performance * * *.'' Northern Indiana believes the opposite is true, *i.e.*, system performance has a significant impact on load models. The goal of the models is to attempt to capture system performance.

1780. MidAmerican supports the proposed clarifications to operating steps and to footnote (b). International Transmission states that more clarification should be provided for the thresholds of normal and emergency ratings. There are potential inconsistencies with respect to whether or not an entity can plan to operate above normal ratings, but below emergency ratings, and for how long.

1781. Northern Indiana also takes issue with the NOPR proposal that no load or transactions be interrupted except for consequential load loss. Attempting to reduce the probability of load loss to zero would greatly increase capital spending, and therefore increase rates to customers, and all in the name of achieving an unattainable goal. PG&E disputes that the Reliability Standard should provide limits on the magnitude and duration of consequential load loss. Determining the magnitude and consequences of load loss is a factor in the economic evaluation during the development of transmission expansion plans. This economic evaluation is not an appropriate subject for this Reliability Standard. Northern Indiana urges the Commission to acknowledge that planning studies by nature must balance infrastructure improvement and expansion against site-specific and regional load projections, using available resources. It questions whether the NOPR reflects a proper balance between the many costs involved and the benefits, if any, that would be realized.

1782. Entergy opposes the Commission's proposed guidance concerning footnote (b) to Table 1 for two reasons. First, Entergy believes the Commission should give due weight to the technical expertise of NERC and permit NERC to address these matters through Reliability Standards development process. Second, the Commission's guidance suggests that it views all transmission outages as having the same level of importance to and impact on the interconnected transmission grid. Entergy states that the Commission should recognize that the effect of transmission outages can be local in nature and have no impact on the reliability of the Bulk Power System. Removing the transmission operator's ability to shed load or enact other system adjustments as appropriate for a single contingency would result in significant facility upgrade costs simply to avoid the consequence of a local outage. Entergy requests that the Commission clarify that its guidance does not constrain the transmission operator's ability to determine the best course of action to take to address any reliability constraint that may result from these local outages.

1783. PG&E disagrees with the Commission's proposal to delete from footnote (b) of this Reliability Standard the phrase ''to prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers.'' [455] PG&E states that this phrase permits critical system adjustments to reduce the potential for and impact of future contingencies. It would allow re-scheduling power (but not load shedding) as part of manual system adjustment after the first Category B contingency (first N–1) to bring the system back to a safe operating point before the next Category B contingency (second N–1). This phrase is consistent with the manual system adjustment allowed in Category C.3.[456] PG&E states that, contrary to the Commission's interpretation, footnote (c) does not capture this phrase. The difference between footnote (b) as part of Category B and Category C.3 is that footnote (b) applies before the second N–1, whereas Category C.3 applies after the second N–1. Without this phrase in footnote (b), no manual system adjustment would be

[454] NOPR at P 1081.

[455] *Id.* at P 1084.

[456] From TPL Standards Table 1, Category C.3 is Category B (B1, B2, B3 or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3 or B4) contingency.

allowed after a Category B contingency, which would be inconsistent with Category C.3.

1784. APPA and LPPC recommend that changes to the footnotes of Table 1 be subject to the NERC Reliability Standards development process. They state that the footnotes have been extensively reviewed by technical experts at NERC for several years and currently represent a general consensus among these industry technical experts. Changes to the footnotes affect Table 1 and have a direct impact on the determination of the severity of consequences that were approved along with the original standard. APPA also states that consideration of reliability impacts of spare equipment strategies and obligations of all generators to have the same voltage ride through capabilities are important changes that should not be made by Commission fiat.

ii. Commission Determination

1785. The Commission approves TPL–002–0 as a mandatory and enforceable Reliability Standard. In addition, we direct the ERO to develop modifications to TPL–002–0 through the Reliability Standards development process, as discussed below.

1786. The Commission notes that, like Requirement R1.3.1 of TPL–001–0, R1.3.2 of TPL–002–0 requires an entity assessing system performance to cover ''critical system conditions and study years'' as deemed appropriate by the entity performing the study, but it does not specify the rationale for determining critical system conditions and study years. The Commission directs the ERO to modify TPL–002–0 to require that critical system conditions and study years be determined in the same manner as it directed with regard to TPL–001–0. The Commission's explanation of the need for that change applies equally here.

1787. With regard to Northern Indiana's concerns, we disagree that the proposal to address situations in which critical equipment may be unavailable for a prolonged period requires planned and forced outage schedules for the next ten years. Reliability Standard TPL–002–0 requires consideration of planned outages at those demand levels for which planned outages are performed but does not address situations in which critical long lead time equipment, such as a transformer or phase angle regulator, may be unavailable for a prolonged period that could extend into periods where planned outages of such equipment would not normally be performed. Assessments of these situations do not require outage schedules for the next ten years but rather identification of which facilities are deemed to be critical that have long lead times for repair or replacement. Given that planned outage considerations of such long lead time equipment are inexorably linked to spare equipment strategy, consistent with our discussion of the issue above in connection with spare equipment strategy, the Commission directs the ERO to modify the Reliability Standard to require assessments of planned outages of long lead time critical equipment consistent with the entity's spare equipment strategy.

1788. In the NOPR, the Commission identified an implicit assumption in the TPL Reliability Standards that all generators are required to ride through the same types of voltage disturbances and remain in service after the fault is cleared. This implicit assumption should be made explicit. Commenters agree with the proposed requirement for all generators to ride through the same set of Category B and C events as required for wind generators. The Commission understands that NRC has both degraded voltage and loss of voltage requirements. The degraded voltage requirement allows the voltage at the auxiliary power system busses to go below the minimum value for a time frame that is usually much longer than normal fault clearing time.[457] If a specific nuclear power plant has an NRC requirement that would force it to trip off-line if its auxiliary power system voltage was depressed below some minimum voltage, the simulation should include the tripping of the plant in addition to the faulted facilities. In this regard, the Commission agrees that NRC requirements should be used when implementing the Reliability Standards. Using NRC requirements as input will assure that there is consistency between the Reliability Standards and the NRC requirement that the system is accurately modeled. Accordingly, the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. If a generator trips due to low voltage from a single contingency, the initial trip of the faulted element and the resulting trip of the generator would be governed by Category B contingencies and performance criteria.

1789. The Commission agrees with NRC that for operations purposes the N–1 condition is always analyzed from the conditions being experienced. In other words, allowing for the 30 minute system adjustment period, the system must be capable of withstanding an N–1 contingency, with load shedding available to system operators as a measure of last resort to prevent cascading failures. However, for planning purposes, a different analysis applies. The N–1 condition is a Category B event under TPL–002–0, and, following the N–1 contingency, the system must be stable and thermal loading and voltages be within applicable limits. Some adjustment of generation or other controls is permitted to return loadings to within continuous ratings, provided the loadings before adjustments are within the emergency or short-term ratings. Under TPL–002–0 the system is not required to be able to withstand another N–1 contingency. That N–1 requirement is a Category C contingency which is addressed by TPL–003–0. The Commission has addressed NRC's comment concerning N–1 contingencies in real-time operation in TOP–002. In regard to the specific revisions proposed by NRC, the Commission directs the ERO to consider these as part of the Reliability Standards development process.

1790. In regard to Northern Indiana's comment concerning the load modeling statement made in the NOPR, it should be clear that the context of the discussion is system performance during simulations. Load models used in simulations clearly should, to the extent feasible, represent the actual performance of the aggregate mix of industrial, commercial and residential loads. If the load model representations used in simulations do not mirror the actual performance of loads, especially during dynamic simulations, but also when carrying out voltage stability studies, the simulation results will not be accurate. Because load representation in simulations has a significant impact on simulation results and often load models are not well known, it is common practice for planners to perform sensitivity studies with a range of load models. Accordingly, as proposed in the NOPR, the Commission directs the ERO to modify the Reliability Standard to require documentation of load models used in system studies and the supporting rationale for their use.

1791. In the NOPR, the Commission set forth its rationale for proposing that the ERO clarify the phrase ''permit operating steps necessary to maintain system control'' in footnote (a) to Table 1.[458] Specifically, the Commission stated that the operating steps required

[457] 10 CFR 50, Appendix a, GDC17.

[458] NOPR at P 1083.

to relieve emergency loadings and return the system to a normal state should not include firm load shedding. MidAmerican agrees with the Commission. International Transmission states clarification is required on the thresholds for normal and emergency ratings and, in particular, on whether an entity can plan to operate above normal ratings but below emergency ratings and for how long. The Commission agrees that this issue requires clarification and therefore directs the ERO to modify the standard to clarify the phrase of footnote (a) that states ''permit operating steps necessary to maintain system control'' to clarify the use of emergency ratings.

1792. The Commission stated in the NOPR that footnote (b) raises three issues that need to be addressed.[459] Two relate to the use of planned or controlled load interruption under certain circumstances, and the third relates to the use of system adjustments including curtailment of firm transfers to prepare for the next contingency. Northern Indiana and Entergy disagree with the Commission's proposal to modify footnote (b) to state that load shedding for a single contingency is not permitted except in very special circumstances where such interruption is limited to the firm load associated with the failure (consequential load loss). The commenters argue that the impact of transmission outages can be local in nature and have no impact on the reliability of the Bulk-Power System and that removing the option to shed load in a local area for a single contingency would result in significant facility upgrade costs and therefore increased rates to customers simply to avoid a local outage. Entergy seeks clarification that the Commission does not intend to constrain the transmission operator's ability to determine the best course of action to address local reliability constraints.

1793. The NOPR proposed a modification that would clarify footnote (b) as disallowing loss of such firm load or the curtailment of firm transactions after a first contingency of the bulk electric system. In its comments to the Staff Preliminary Assessment, NERC agreed with this interpretation, representing that a practice that permits the planned interruption of ''firm transmission service'' is a misapplication of the Reliability Standard.[460] Some commenters now argue otherwise, and in some cases cite examples where, based on a balance of economic and reliability considerations, it may be preferable to plan the bulk electric system in such a manner that contemplates the interruption of some firm load customers in the event of a N–1 contingency. We view these arguments as based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N–1 scenarios. Therefore, they argue, the ambiguities of footnote (b) should be interpreted to allow that an entity plan for some amount of load loss to avoid costly infrastructure investments.

1794. The Commission considers this matter to be a fundamental issue of transmission service. Indeed, the ERO's definition of ''firm transmission service'' specifically states that it is the ''highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.''

1795. Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency.[461] The Commission directs the ERO to clarify the Reliability Standard. Regarding the comments of Entergy and Northern Indiana that the Reliability Standard should allow entities to plan for the loss of firm service for a single contingency, the Commission finds that their comments may be considered through the Reliability Standards development process. However, we strongly discourage an approach that reflects the lowest common denominator.[462] The Commission also clarifies that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances.

1796. PG&E disputes that the Reliability Standard should provide limits on the magnitude and duration of consequential load loss, as this is an economic evaluation and is not an appropriate goal for this Reliability Standard. The Commission disagrees. Indeed in its comments to the Staff Preliminary Assessment, the ERO raised the issue of what is an acceptable magnitude and duration of consequential load loss.[463] The Commission notes that most utilities have guidelines for the magnitude and duration of load loss that is acceptable on radial facilities before the facilities are looped to provide a second source of supply to accommodate load growth. NERC also stated that it recognizes that looped configurations are key to the reliable operation of the Interconnection and to meet reasonable expectations for reliable service to loads.[464] The Commission, therefore, suggests that the ERO consider developing a ceiling on the amount and duration of consequential load loss that will be acceptable. If the ERO determines that such a ceiling is appropriate, it should be developed through the ERO's Reliability Standards development process. Further, we note that the DOE thresholds for reporting disturbances on Form EIA–417 would be one example of an appropriate starting point for developing such a ceiling. These thresholds for load loss are 300 MW for 15 minutes or 50,000 customers for one hour, whichever is greater.

1797. The third issue with footnote (b) relates to the Commission's proposal in the NOPR to delete the footnote's second sentence, which states ''[t]o prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers.'' [465] PG&E disagrees with the Commission's proposal because it allows re-scheduling power (but not load shedding) as part of manual adjustment after the first Category B contingency to bring the system back to a safe operating point. The Commission agrees that footnote (b) should permit manual adjustments including generation redispatch and transmission reconfiguration, but not load shedding, to return the system to a normal operating state within the time period permitted by the emergency or short term ratings. The Commission understands that this is the normal practice used by most transmission planners. However, the system adjustments permitted in the statement above includes curtailments of contracted firm, non-recallable reserved and electric power transfers and this is not acceptable for Category B single contingencies. Therefore, the ERO should modify the sentence to indicate that manual system adjustments, except

[459] *Id.* at P 1084.

[460] ''NERC standards, including footnote (b), are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for a single contingency.'' NERC comments to the Staff Preliminary Assessment at 57–58.

[461] Consequential load is the load that is directly served by the elements that are removed from service as a result of the contingency.

[462] *See* Order No. 672 at P 329.

[463] NERC Comments to Staff Preliminary Assessment at 56–57.

[464] ''NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads.'' *Id.* at 57.

[465] NOPR at P 1083.

for shedding firm load or curtailment of firm transfers, are permitted after the first contingency to bring the system back to a normal operating state. The Commission disagrees with PG&E's statement that the difference between footnote (b) as part of Category B and Category C.3 is that footnote (b) applies before the second N–1 contingency, whereas Category C.3 applies after the second N–1 contingency. Rather, manual adjustments referred to in both cases apply after the first N–1 contingency. The Commission, therefore, directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.

1798. Accordingly, the Commission approves Reliability Standard TPL–002–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL–002–0 through the Reliability Standards development process that: (1) Requires that critical system conditions be determined in the same manner as we propose to require for TPL–001–0; (2) requires assessments of planned outages of long lead time critical equipment consistent with the entity's spare equipment strategy; (3) requires all generators to ride through the same set of Category B and C contingencies as required by wind generators in Order No. 661, or to simulate those generators that cannot ride through as tripping; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase ''permit operating steps necessary to maintain system control'' in footnote (a) and the use of emergency ratings and (6) clarifies footnote (b) in regard to load loss following a single contingency, specifying the amount and duration of consequential load loss and system adjustments permitted after the first contingency to return the system to a normal operating state, as discussed above.

d. System Performance Following Loss of Two or More Elements (TPL–003–0)

1799. Reliability Standard TPL–003–0 seeks to ensure that the future Bulk-Power System is planned to meet the system performance requirements of a system with the loss of multiple elements. It does this by requiring that the transmission planner and the planning authority annually evaluate and document the ability of its transmission system to meet the performance requirements of Category C contingencies specified in Table 1 (*i.e.*, events resulting in the loss of two or more elements) for both the near-term and the longer-term planning horizons. TPL–003–0 requires the preparation of a documented plan to achieve the necessary performance requirements if the system is unable to meet the Category C performance criteria.

1800. TPL–003–0 applies to each planning authority and transmission planner. They must demonstrate annually through valid assessments that their portion of the interconnected transmission system is planned to meet the performance requirements of Category C with all transmission facilities in service over a planning horizon that takes into account lead times for corrective plans. The Reliability Standard also requires the applicable entities to consider planned outages of transmission equipment for those demand levels for which they perform such outages. The Reliability Standard defines various categories of conditions to be simulated. The specific study elements selected from each of the categories for assessments, including the subset of Category C contingencies to be evaluated, require approval by the associated regional reliability organization.

1801. The Commission proposed in the NOPR to approve Reliability Standard TPL–003–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL–003–0 that: (1) Requires that critical system conditions be determined by conducting sensitivity studies (as elaborated in our discussion of TPL–001–0); (2) makes certain clarifications to footnote (c) to Table 1; (3) requires the applicable entities to define and document the proxies necessary to simulate cascading outages and (4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

1802. The Commission also sought comments on one potential addition to TPL–003–0. It noted that Category C3 of this Reliability Standard involves a situation in which two single contingencies occur, with manual system adjustments permitted after the first contingency to prepare for the next one (generally referred to as N–1–1). However, the Commission also noted that should the second contingency occur before the manual system adjustments can be completed, the local area and potentially the system would be exposed to risk of cascading outages. For that reason some entities plan and operate their systems so that they are able to withstand the simultaneous occurrence of the two contingencies (normally referred to as N–2) for major load pockets. The Commission sought comments on the value and appropriateness of including such a requirement in TPL–003–0.

i. Comments

1803. LPPC recommends that changes to footnotes of Table 1 be subject to the NERC Reliability Standards development process. It states that the footnotes have been extensively reviewed by technical experts at NERC for several years and currently represent a general consensus among these industry technical experts which should be given due weight by the Commission. Changes to the footnotes impact Table 1 and have a direct impact on the determination of the severity of consequences that were approved along with the original Reliability Standard.

1804. FirstEnergy supports the proposed requirement to document proxies of subsequent line trips due to thermal overload and low voltage generation trips to evaluate potential cascading conditions. FirstEnergy states it currently is required to account for these items in its planning process.

1805. EEI questions the value of providing proxies when planners conduct thousands of studies based on combinations of contingencies under a broad range of circumstances and conditions, especially in longer-term planning horizons where the uncertainty around the value of any one variable is already very high. SoCal Edison states that one can determine the cascading outages in load flow studies. In transient stability studies, if the outage is severe, then the thermal overload relays and undervoltage relays, if modeled, will trip the load. If the load tripped was not planned to be tripped for this outage, then the planning authority should take the necessary steps to avoid this situation, as cascading is not allowed.

1806. LPPC and Northern Indiana oppose the proposal to require proxies necessary to simulate cascading outages be defined and documented. Northern Indiana states that there is no consensus on what these proxies should be. LPPC states that utility planners have traditionally used their engineering judgment to simulate a conservative estimate of the level of thermal overload or low voltage that will cause the likelihood of subsequent line or generator trips and cascading events. LPPC states that this approach has been

successful, and NERC should not be asked to second-guess the decisions of operators in this area. That could result in the adoption of less conservative, least common denominator, design assumptions across all regions and reduce modeling flexibility and use of engineering judgment. Proxies are typically tailored to specific systems because the development of proxies is highly dependent on regional differences and localized knowledge. If the Commission determines that independent review of utility outage simulation proxies is necessary, Regional Entities should conduct that review, because they better understand the regional and localized factors that influence the proxies.

1807. EEI requests that the Commission clarify the meaning of the term ''controlled load interruption'' and the meaning of its statement that ''to avoid undue negative impact on competition, third party studies could be permitted to implement the same or less controlled load interruption as used by the transmission owner.'' [466]

1808. NRC states that this Reliability Standard should be clarified in regard to the N–1–1 condition. In addition, it recommends specific changes to Requirements R1.6, R.1.2 and R2.2.

1809. A number of commenters respond to the Commission's request for comments on the value and appropriateness of including the ability of the system to withstand two simultaneous contingencies for major load pockets. NERC states that this issue has been recognized as needing clarification, and it welcomes comments in the development of these revisions in accordance with its Reliability Standards development process. NERC states that it is developing a proposal for a transmission availability data system that will provide a quantitative (probabilistic) basis for judging the likelihood of various multi-element contingencies which will be helpful in determining the value of this proposal.

1810. APPA, LPPC and National Grid state that imposing N–2 planning may be difficult to administer since there is no consensus on what constitutes a ''major load pocket.'' LPPC states that the definition of major load pockets has been, and is still being debated. As there is no nation-wide consensus on the term's definition, no list of major load pockets exists. Because load pockets and their boundaries change with the dynamically changing system and load patterns, it is difficult to establish or administer a rule that encompasses the particular sub-region to which such an N–2 requirement would apply.

1811. APPA and EEI believe such provisions would significantly expand planning requirements for extremely unlikely events that in most cases are not cost effective to build into system planning decisions. They explain that the Reliability Standard currently includes the more likely situation, *i.e.*, where two events occur in a time frame that allows some time to adjust in response to the first event. APPA and EEI state that various planning entities may, of course, study much more extreme events, including the hypothetical the Commission poses, especially if formal state or regional planning requires such studies, and actual preparation for extreme events is viewed as cost-effective in a particular area. However, this level of planning sensitivity is simply unnecessary for many regions of the country. They ask that if the Commission envisions changes to provide for N–2 service to load pockets, a dialogue must first be initiated within the industry and with state public utility commissions to identify such load pockets, target the required transmission investments (which could be very substantial) and develop plans for allocating the costs of such investments.

1812. FirstEnergy comments that, although simultaneous C.3 independent contingencies may pose potentially high risk, they are most likely extremely low in probability. FirstEnergy states that it nevertheless routinely evaluates these contingencies across its system for facilities 200 kV and higher and suggests that if this analysis is made a requirement, it should be limited to an extra high voltage subset of the Bulk-Power System.

1813. MISO believes that evaluation of multiple contingency events should only reside in the planning arena and not in the operations environment. It states that the current Reliability Standard provides a reasonable and time tested methodology.

1814. National Grid opposes applying this N–2 criterion across the board. It states that N–2 planning is usually relied upon when a particular area does not have the resources or flexibility to adopt the N–1–1 approach. The Bulk-Power System is designed differently in every region, and there is no need to impose N–2 planning where regions are satisfactorily implementing the N–1–1 methodology.

1815. SDG&E states that the N–2 consideration for major load pockets is neither of value nor appropriate for transmission planning entities at large. The probability of such a contingency for a major load pocket is very low, and the costs for addressing such a remote contingency would be significant. SoCal Edison states the potential number of multi-contingency events that could be studied under TPL–003–0 is staggering. Planners should be given flexibility to select generation and transmission elements that reflect a broad range of potential combinations without having to commit resources to conduct potentially hundreds or thousands of contingency studies. Northern Indiana contends that this requirement is in effect a third back-up capability, that it would be prohibitive in terms of time and cost, and that it would take many years to put the infrastructure it would require into place.

1816. PG&E believes there is no need for a general requirement to withstand the simultaneous occurrence of any two contingencies for major load pockets. It states that IRO–005 provides for contingencies that are credible when operating below IROL in current day operations. The TPL group of Reliability Standards already require provisions for specific circumstances based on evaluations that take into account the probability of an outage occurring and the associated consequences when transmission plans are developed. PG&E states that TPL–003–0, Category C.5 contingency already addresses the more probable simultaneous outages (due to common-mode failure) that could occur. PG&E maintains that simultaneous occurrence of other contingencies is not credible. The principles incorporated in the Reliability Standards require that evaluations of credibility be balanced against potential impact, and investing resources to prevent improbable events diverts attention and focus from more critical Reliability Standards and more probable conditions.

ii. Commission Determination

1817. The Commission approves proposed Reliability Standard TPL–003–0 as a mandatory and enforceable Reliability Standard. In addition, we direct the ERO to develop modifications to TPL–003–0 through the Reliability Standards development process, as discussed below.

1818. The Commission notes that, like Requirement R1.3.1 of TPL–001–0, Requirement R1.3.2 of TPL–003–0 requires an entity assessing system performance to cover ''critical system conditions and study years'' as deemed appropriate by the entity performing the study, but that the Requirement does not specify the rationale for determining critical system conditions and study years. The Commission directs the ERO to modify TPL–003–0 to require that

[466] *Id.* at P 1097.

critical system conditions and study years be determined in the same manner as we directed with regard to TPL–001–0, for the reasons as set forth in our discussion of TPL–001–0.

1819. The intent underlying the statement that ''to avoid undue negative impact on competition, third party studies should be permitted to implement the same or less controlled load interruption as used by the transmission owner'' is to ensure that third parties have access to the same options that the transmission owner uses to alleviate reliability constraints including those related to controlled load shedding. For example, if a transmission owner designs its system to result in a controlled load shedding of 300 MW for Category C contingencies, designs proposed for third parties requesting interconnections to that system must also be permitted, but not required, to have 300 MW of controlled load shedding for the same Category C contingencies. The Commission directs the ERO to modify footnote (c) of Table 1 to the Reliability Standard to clarify the term ''controlled load interruption.'' In response to LPPC's comments on modification procedures, the Commission agrees that changes to the footnotes of Table 1 should be addressed through the ERO's Reliability Standards development process.

1820. The Commission stated in the NOPR that the concern involved relates to the use of thermal overloads or low voltage proxies to judge the likelihood of subsequent line or generator trips leading to a cascading outage.[467] The Commission agrees with SoCal Edison that, if an entity models overload relays, undervoltage relays, all remedial action schemes including those of neighboring systems and has a good load representation, then proxies are not required. However, due to modeling and simulation limitations this is often not the case and planners invariably use proxies.[468] Recognizing this and the range of proxies currently in use, the Transmission Issues Subcommittee of the NERC Planning Committee recommended that proxies used in simulations be defined until such time as improved analytical tools and models are available to simulate cascading events.

1821. The Commission disagrees with LPPC that defining and documenting proxies will result in the adoption of less conservative, least common denominator design assumptions across all regions and reduce modeling flexibility and engineering judgment. To the contrary, the Commission believes that such sharing of information will improve knowledge and understanding and promote a more rigorous approach to analyzing cascading outages. The Commission agrees with LPPC that it may be preferable for the Regional Entities to conduct the review of proxies, because they better understand the regional and localized factors that influence the proxies. However, we expect the ERO to coordinate between regions to assure that best practices are shared among the Regional Entities. Accordingly, the Commission directs the ERO to modify the Reliability Standard to require definition and documentation of proxies necessary to simulate cascading outages.

1822. No comments were received on the Commission's proposal that the purpose statement of TPL–003–0 be tailored to reflect the specific goal of the Reliability Standard. The Commission directs that this modification be made. Reliability Standards should be clear and unambiguous, and a clear statement of a Reliability Standard's purpose and goal is one of the features necessary to achieve this end.

1823. The NRC's comments on TPL–003–0 parallel its comments on TPL–002–0. The Commission discussed those comments above, and its conclusions there apply equally here. The Commission, for the same reasons set forth in our discussion of TPL–002–0, directs the ERO to address NRC concerns through its Reliability Standards development process.

1824. The Commission received numerous comments on its request for comments on the appropriateness and value of including the ability of the system to withstand two simultaneous Category B contingencies for major load pockets. The Commission stated that it was aware that several entities currently apply this approach and notes that one entity was actually commended by NERC for doing so as part of its readiness review. FirstEnergy states that it routinely evaluates these contingencies across its system for 200 kV and higher. NERC states that this issue has been recognized as requiring clarification, and it welcomes comments on these revisions in accordance with the Reliability Standards development process.

1825. Many commenters state that, without a consensus on what constitutes a major load pocket, little progress can be made in this regard. LPPC states that the definition of major load pockets has been and is still being debated. National Grid states that N–2 planning is usually relied upon when a particular area does not have the resources and flexibility to adopt the N–1–1 approach. The Commission agrees with National Grid but notes that this is more applicable to the operating domain, something that MISO opposes. PG&E states that this approach is not necessary because Category C5 already addresses more probable simultaneous outages due to common mode failure. The Commission disagrees since Category C5 only deals with a loss of any two circuits on a multi-circuit tower line and not a simultaneous loss of a line and a generator which was envisaged by the request for comments. Many commenters indicated that this was a very low probability event and the costs for addressing such an event would be significant. As a result, EEI states that a dialogue must first be initiated within the industry and with state public utility commissions to identify such load pockets, to target the required potentially significant transmission investments and to develop plans for allocating the costs of such investments. In light of these comments, the Commission does not intend to recommend action on this issue at this time and, instead, directs the ERO to consider the comments in possible future revisions to the Reliability Standard.

1826. Accordingly, the Commission approves Reliability Standard TPL–003–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL–003–0 through the Reliability Standards development process that: (1) Requires that critical system conditions be determined in the same manner as we propose to require for TPL–001–0; (2) modifies footnote (c) to Table 1 to clarify the term ''controlled load interruption;'' (3) requires applicable entities to define and document the proxies necessary to simulate cascading outages and (4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

e. System Performance Following Extreme Events (TPL–004–0)

1827. The goal of Reliability Standard TPL–004–0 is to ensure that the future Bulk-Power System is evaluated to assess the risks and consequences of an extreme event involving the loss of multiple elements. It seeks to do this by requiring the transmission planner and the planning authority to evaluate and document annually the risks and consequences of Category D contingencies (*i.e.*, extreme events

[467] *Id.* at P 1098.

[468] *See* WECC Disturbance Performance Table W–1 and Figure W–1 of Allowable Effects on other Systems, NERC/WECC Planning Standards April 10, 2003.

resulting in loss of two or more elements or cascading) for the near-term (five-year) planning horizon.

1828. TPL–004–0 applies to each planning authority and transmission planner. Each must demonstrate annually through valid assessments that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies of Category D with all transmission facilities in service over a planning horizon that takes into account lead times for corrective plans. TPL–004–0 also requires that planned outages of transmission equipment be considered for those demand levels for which planned outages are performed. It defines various categories of conditions to be simulated. The associated regional reliability organization must approve the specific study elements selected from each of the categories for assessment, including the subset of Category D contingencies to be evaluated.

1829. The Commission proposed in the NOPR to approve Reliability Standard TPL–004–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL–004–0 that: (1) Requires that critical system conditions be determined in the same manner as proposed for TPL–001–0; (2) requires the identification of options for reducing the probability or impacts of extreme events that cause cascading; (3) requires that, in determining the range of extreme events to be assessed, the contingency list of Category D be expanded to include recent events and (4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

i. Comments

1830. MidAmerican supports the Commission's proposed modifications to the Reliability Standard as reasonable and agrees with the Commission that the Reliability Standard should not require improvements for low probability events that cannot be justified.[469] MidAmerican supports developing options for any events listed in TPL–004–0 that result in cascading outages and suggests use of probabilistic estimates to determine which, if any, of the TPL–004 extreme events options should be estimated to reduce their probability or impacts.

1831. FirstEnergy, EEI, APPA, TVA and Northern Indiana all oppose the expansion of the list of extreme contingencies to include natural disasters such as hurricanes and ice storms. They state that the potential contingencies resulting from this expansion are endless and therefore impractical to consider through engineering studies. As a result, additional requirements in this Reliability Standard are unnecessary. EEI and APPA state that to the extent that such events will happen, entities historically have put heavy emphasis on emergency planning and procedures, which are addressed by the EOP group of Reliability Standards.

ii. Commission Determination

1832. The Commission approves proposed Reliability Standard TPL–004–0 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to TPL–004–0 through the Reliability Standards development process, as discussed below.

1833. The Commission notes that, like Requirement R1.3.1 of TPL–001–0, Requirement R1.3.2 of TPL–004–0 requires an entity assessing system performance to cover ''critical system conditions and study years'' as deemed appropriate by the entity performing the study, but it does not specify the rationale for determining critical system conditions and study years. The Commission directs the ERO to modify TPL–004–0 to require that critical system conditions and study years be determined in the same manner as we directed with regard to TPL–001–0 and for the reasons stated there.

1834. MidAmerican states that it supports the proposal to modify TPL–004–0 to require identification of options for reducing the probability or impacts of extreme events that cause cascading. Accordingly, for the reasons cited in the NOPR, the Commission directs the ERO to modify the Reliability Standard to make this modification to the Reliability Standard.

1835. All commenters that responded on the issue opposed the Commission's proposal to modify TPL–004–0 to require that, in determining the range of the extreme events to be assessed, the contingency list of Category D be expanded to include recent events such as hurricanes and ice storms. The Commission is not persuaded by the commenters' contention that expansion of the extreme events list will lead to an endless list of possibilities. The two that the Commission used are examples from the general news media. While the NOPR referred to two recent events, other examples include: (1) Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation; (2) a successful cyber attack; (3) regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation; (4) shutdown of a nuclear power plant and other facilities a day or more prior to a hurricane, tornado or wildfire, or other event and (5) the loss of older transmission lines, which may not be constructed to meet an entity's present radial ice loading requirements, while the newer or stronger transmission lines remain in service. The above examples are not an exhaustive list, however, the Commission would not expect the range of scenarios to be much more extensive than this, either. Thus, we are not expecting an endless list of scenarios and infinite number of combinations in directing this modification. Each event is identifiable for each entity based on its topology, facilities and generation mix. Accordingly, the Commission directs the ERO to expand the list of events with examples of such events identified above.

1836. The Commission received no comments on its proposal to modify the purpose statement of TPL–004–0 to reflect the specific goal of the Reliability Standard. The Commission directs that this modification be made.

1837. Accordingly, the Commission approves Reliability Standard TPL–004–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL–004–0 through the Reliability Standards development process that: (1) Requires that critical system conditions be determined in the same manner as proposed for TPL–001–0; (2) requires the identification of options for reducing the probability or impacts of extreme events that cause cascading; (3) requires that, in determining the range of extreme events to be assessed, the contingency list of Category D be expanded to include recent events and (4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

f. Regional and Interregional Self-Assessment Reliability Reports (TPL–005–0)

1838. Reliability Standard TPL–005–0 seeks to ensure that each regional reliability organization conducts reliability assessments of its existing and planned regional bulk electric system annually by requiring it to assess and document the performance of its power system for the current year, the next five years, and to analyze trends for the longer-term planning horizons.

1839. The Commission proposed in the NOPR not to approve or remand

[469] *See* NOPR at P 1112.

TPL–005–0, as it applies only to regional reliability organizations.

i. Comments

1840. EEI comments that TPL–005–0 should be revised to remove the regional reliability organizations.

ii. Commission Determination

1841. Consistent with our discussion in the Common Issues section above, we will not approve or remand TPL–005–0 until we receive additional information from the ERO.

1842. In Order No. 890, the Commission stated that there will be a series of technical conferences and regional meetings to obtain industry input to achieving the goal of regional planning.[470] The Commission encourages the ERO to monitor those proceedings and use the results as input to the Reliability Standards development process in revising Reliability Standard TPL–005–0 to address regional planning and related processes.

g. Assessment Data From Regional Reliability Organizations (TPL–006–0)

1843. Reliability Standard TPL–006–0 seeks to ensure that the data necessary to conduct reliability assessments is available by requiring the regional reliability organization to provide NERC with Bulk-Power System data, reports, demand and energy forecasts, and other information necessary to assess reliability and compliance with NERC Reliability Standards and relevant regional planning criteria.

1844. The Commission proposed in the NOPR not to approve or remand TPL–006–0, as it applies only to regional reliability organizations.

i. Comments

1845. EEI agrees that TPL–006–0 should be revised to remove the regional reliability organizations.

ii. Commission Determination

1846. Consistent with our discussion in the Common Issues section above, the Commission will not approve or remand TPL–006–0.

13. VAR: Voltage and Reactive Control

1847. The Version 0 Voltage and Reactive Control (VAR) Reliability Standard VAR–001–0 is intended to maintain Bulk-Power System facilities within voltage and reactive power limits, thereby protecting transmission, generation, distribution, and customer equipment and the reliable operation of the Interconnection. The Voltage and Reactive Control group of Reliability Standards is intended to replace the existing VAR–001–0 and consists of two proposed Reliability Standards, VAR–001–1 and VAR–002–1, with new Requirements. These two new proposed Reliability Standards have been submitted by NERC as part of the August 28, 2006 Supplemental Filing for Commission review. NERC requested an effective date of February 2, 2007 for VAR–001–1, and August 2, 2007 for VAR–002–1.

a. VAR–001–1 Voltage and Reactive Control

1848. Reliability Standard VAR–001–1 requires transmission operators to implement formal policies for monitoring and controlling voltage levels, acquire sufficient reactive resources, specify criteria for generator voltage schedules, know the status of all transmission reactive power resources, operate or direct the operation of devices that regulate voltage and correct IROL or SOL violations resulting from reactive resource deficiencies. VAR–001–1 also requires purchasing-selling entities to arrange for reactive resources to satisfy their reactive requirements.

1849. In the NOPR, the Commission proposed to approve VAR–001–1 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to VAR–001–1 that: (1) Expands the applicability to include reliability coordinators and LSEs; (2) includes detailed and definitive requirements on ''established limits'' and ''sufficient reactive resources,'' and identifies acceptable margins above the voltage instability points; (3) includes Requirements to perform voltage stability assessments periodically during real-time operations and (4) includes controllable load among the reactive resources to satisfy reactive requirements. The Commission also requested comments concerning NERC's assertion that all LSEs are also purchasing-selling entities, and on the acceptable ranges of net power factor range at the interface at which the LSEs receive service from the Bulk-Power System during normal and extreme load conditions.

1850. Most comments address the specific modifications and concerns raised by the Commission in the NOPR. Below, we address each topic separately, followed by an overall conclusion and summary.

i. Applicability to Load-Serving Entities and Reliability Coordinators

(a) Comments

1851. EEI agrees with the Commission that the applicability of VAR–001–1 should be expanded to include reliability coordinators and LSEs.

1852. MISO contends that the view and role of generator operators, transmission operators and reliability coordinators are different, and reliability coordinators' monitoring and response requirements are addressed elsewhere in the Reliability Standards.

1853. In response to the Commission's request in the NOPR for comments concerning whether all LSEs are also purchasing-selling entities, SoCal Edison believes they are distinguishable. It states that a purchasing-selling entity, according to the functional model, makes financial deals across balancing authorities (from source to sink). Within the area of a large balancing authority, such as the CAISO, an LSE can serve load from a resource within the balancing authority, so that there is no requirement to tag this transaction, and technically there is no purchasing-selling entity involved.

1854. APPA is concerned that requiring VAR–001–1 to be applicable to LSEs would require LSEs to conduct various studies and perform reliability functions that have been assigned to other functional entities. The role of LSEs in voltage stability assessments should be limited to coordination and the provision of data. TAPS also questions the need to expand applicability of these Reliability Standards to LSEs. TAPS maintains that purchasing and selling utilities are already subject to the Reliability Standards, and are required to satisfy any reactive requirements through purchasing Ancillary Service No. 2 under the OATT (or self-supply). TAPS believes that the addition of LSEs as an additional applicable entity serves no reliability purpose.

(b) Commission Determination

1855. In a complex power grid such as the one that exists in North America, reliable operations can only be ensured by coordinated efforts from all operating entities in long-term planning, operational planning and real-time operations. To that end, the Staff Preliminary Assessment recommended and the NOPR proposed that the applicability of VAR–001–1 extend to reliability coordinators and LSEs.

1856. Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is

[470] Order No. 890 at P 443.

important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR–001–1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR–001–1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR–001–1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR–001–1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities.

1857. The Commission agrees with SoCal Edison that not all LSEs are purchasing-selling entities, because not all LSEs purchase or sell power from outside of their balancing authority area. This understanding is consistent with the NERC functional model and NERC glossary. Both LSEs and purchasing-selling entities should have some requirements to provide reactive power to appropriately compensate for the demand they are meeting for their customers. Neither a purchasing-selling entity nor a LSE should depend on the transmission operator to supply reactive power for their loads during normal or emergency conditions.

1858. VAR–001–1 recognizes that energy purchases of purchasing-selling entities can increase reactive power consumption on the Bulk-Power System and the purchasing-selling entities must supply what they consume. The Commission agrees with APPA that LSEs would provide data for voltage stability assessments. However, the Commission also believes that LSEs have an active role in voltage and reactive control, since LSEs are responsible for maintaining an agreed-to power factor at the interface with the Bulk-Power System.

1859. While the Commission recognizes the point made by TAPS, that purchasing-selling entities are required to satisfy any reactive requirements through purchasing Ancillary Service #2 under the OATT or self-supply, the Commission disagrees that adding LSEs to this Reliability Standard serves no reliability purpose. As discussed in the NOPR and the Staff Preliminary Assessment, LSEs are responsible for significantly more load than purchasing-selling entities.[471] The reactive power requirements can have significant impact on the reliability of the system and LSEs should be accountable for that impact in the same ways that purchasing-selling entities are accountable, by providing reactive resources, and also by providing information to transmission operators to allow transmission operators to accurately study the reactive power needs for both the LSEs' and purchasing-selling entities' load characteristics.[472] The Commission recognizes that all transmission customers of public utilities are required to purchase Ancillary Service No. 2 under the OATT or self-supply, but the OATT does not require them to provide information to transmission operators needed to accurately study reactive power needs. The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.

ii. Acceptable Ranges of Net Power Factor Range

(a) Comments

1860. SoCal Edison states that its Bulk-Power System facilities are designed and operated to provide a unity power factor during normal load conditions, and that during extreme load conditions, this power factor could be in the range of 0.95 to 1.0.

1861. APPA contends that it may be difficult to reach an agreement on acceptable ranges of net power factors at the interfaces where LSEs receive service from the Bulk-Power System because the acceptable range of power factors at any particular point on the electrical system varies based on many location-specific factors. APPA further states that system power factors will be affected by the transmission infrastructure used to supply the load. As an example, APPA states that an overhead circuit may operate at a higher power factor than an underground cable due to a substantial amount of reactive line charging, and that a transmission circuit carrying low levels of real power will tend to provide more reactive power, which will affect the need to switch off capacitor banks at the delivery point to manage delivery power factors.

(b) Commission Determination

1862. In the NOPR, the Commission asked for comments on acceptable ranges of net power factor at the interface at which the LSEs receive service from the Bulk-Power System during normal and extreme load conditions. The Commission asked for these comments in response to concerns that during high loads, if the power factor at the interface between many LSEs and the Bulk-Power System is so low as to result in low voltages at key busses on the Bulk-Power System, then there is risk for voltage collapse. The Commission believes that Reliability Standard VAR–001–1 is an appropriate place for the ERO to take steps to address these concerns by setting out requirements for transmission owners and LSEs to maintain an appropriate power factor range at their interface. We direct the ERO to develop appropriate modifications to this Reliability Standard to address the power factor range at the interface between LSEs and the Bulk-Power System.

1863. We direct the ERO to include APPA's concern in the Reliability Standards development process. We note that transmission operators currently have access to data through their energy management systems to determine a range of power factors at which load operates during various conditions, and we suggest that the ERO use this type of data as a starting point for developing this modification.

1864. The Commission expects that the appropriate power factor range developed for the interface between the bulk electric system and the LSE from VAR–001–1 would be used as an input to the transmission and operations planning Reliability Standards. The range of power factors developed in this Reliability Standard provides the input to the range of power factors identified in the modifications to the TPL Reliability Standards. In the NOPR, the Commission suggested that sensitivity studies for the TPL Reliability Standards should consider the range of load power factors.[473]

iii. Requirements on ''established limits'' and ''sufficient reactive resources''

(a) Comments

1865. Dynegy supports the Commission's proposal to include more definitive requirements on ''established

[471] NOPR at P 1134.

[472] Purchasing selling entities provide information concerning their load through the INT series of Reliability Standards. Load serving entities would need to provide similar information through this Reliability Standard.

[473] NOPR at P 1047.

limits'' and ''sufficient reactive resources.'' It recommends that VAR–001–1 be further modified to require the transmission operator to have more detailed and definitive requirements when setting the voltage schedule and associated tolerance band that is to be maintained by the generator operator. Dynegy states that the transmission operator should not be allowed to arbitrarily set these values, but rather should be required to have a technical basis for setting the required voltage schedule and tolerance band that takes into account system needs and any limitations of the specific generator. Dynegy believes that such a requirement would eliminate the potential for undue discrimination, as well as the possibility of imposing overly conservative and burdensome voltage schedules and tolerance bands on generator operators that could be detrimental to grid reliability, or conversely, the imposition of too low a voltage schedule and too wide a tolerance band that could also be detrimental to grid reliability.

1866. While MISO supports the concept of including more detailed requirements, it believes that there needs to be a definitive reason for establishing voltage schedules and tolerances, and that any situations monitored in this Reliability Standard need to be limited to core reliability requirements.

1867. EEI seeks clarification about whether the Commission is suggesting that reactive requirements should aim for significantly greater precision, especially in terms of planning for various emergency conditions. If so, EEI cautions the Commission against '' 'putting too many eggs' '' in the reactive power 'basket.' '' [474] To the extent compliance takes place pursuant to all other modeling and planning assessments under the other Reliability Standards, EEI strongly believes that the Commission should have some high level of confidence that the system's reactive power needs can be met satisfactorily across a broad range of contingencies that planners might reasonably anticipate. Moreover, EEI believes that requirements to successfully predict reactive power requirements in conditions of near-system collapse would require significantly more creative guesswork than solid analysis and contingency planning. For example, EEI notes that the combinations and permutations of how a voltage collapse could occur on a system as large as the eastern Interconnection are numerous.

1868. EEI suggests that, alternatively, the Commission should consider that reactive power evaluations should be conducted within a process that is documented in detail and includes a range of contingencies that might be reasonably anticipated, because this would avoid the 'one size fits all' problem, where a prescriptive analytical methodology does not fit with a particular system configuration. EEI believes that this flexible approach would provide a more effective planning tool for the industry, while satisfying the Commission's concerns over potentially inadequate reactive reserves. MRO notes that the need for, and method of providing for, reactive resources varies greatly, and if this Reliability Standard is expanded it must be done carefully. MRO believes that all entities should not be required to follow the same methodology to accomplish the goal of a reliable system.

(b) Commission Determination

1869. In the NOPR, the Commission expressed concern that the technical requirements containing terms such as ''established limits'' or ''sufficient reactive resources'' are not definitive enough to address voltage instability and ensure reliable operations.[475] To address this concern, the NOPR proposed directing the ERO to modify VAR–001–1 to include more detailed and definitive requirements on ''established limits'' and ''sufficient reactive resources'' and identify acceptable margins (*i.e.* voltage and/or reactive power margins) above voltage instability points to prevent voltage instability and to ensure reliable operations. We will keep this direction, and direct the ERO to include this modification in this Reliability Standard.

1870. We recognize that our proposed modification does not identify what definitive requirements the Reliability Standard should use for ''established limits'' and ''sufficient reactive resources.'' Rather, the ERO should develop appropriate requirements that address the Commission's concerns through the ERO Reliability Standards development process. The Commission believes that the concerns of Dynegy, EEI and MISO are best addressed by the ERO in the Reliability Standards development process.

1871. In response to EEI's concerns about a prescriptive analytical methodology, we clarify that the Commission is not asking that the Reliability Standard dictate what methodology must be used to determine reactive power needs. Rather, the Commission believes that the Reliability Standard would benefit from having more defined requirements that clearly define what voltage limits are used and how much reactive resources are needed to ensure voltage instability will not occur under normal and emergency conditions. For example, in the NOPR, the Commission suggested that NERC consider WECC's Reliability Criteria, which contain specific and definitive technical requirements on voltage and margin application. While we are not directing that the WECC reliability criteria be adopted, we believe they represent a good example of clearly-defined requirements for voltage and reactive margins.

1872. In sum, the Commission believes that minimum requirements for voltage levels and reactive resources should be clearly defined by placing more detailed requirements on the terms ''established limits'' and ''sufficient reactive resources'' in the Reliability Standard as discussed in the NOPR and the Staff Preliminary Assessment. As mentioned above, EEI's concerns should be considered in the ERO's Reliability Standards development process.

iv. Periodic Voltage Stability Analysis in Real-Time Operations

(a) Comments

1873. SDG&E supports the NOPR recommendation that a more effective requirement could be based on WECC's reliability criteria, which contain specific and definitive technical requirements on voltage and margin application. MidAmerican and PacifiCorp recommend that the ''WECC Methods to address voltage stability and settling margins'' should be consulted when designing corresponding NERC requirements.

1874. Xcel Energy recommends that this proposed modification instead address requirements to measure reactive power margin for a variety of topology conditions. MidAmerican recommends that the Commission's proposal be modified to require real-time checks for voltage stability assessments only in areas susceptible to voltage instability. Alternatively, MidAmerican suggests that the Commission ''should exempt from these requirements areas that can demonstrate they are not susceptible to voltage instability.''

1875. APPA, SDG&E and EEI all state that they are not aware of commercially-available tools to provide real-time transient stability assessments as part of an integrated energy management system for operators. APPA notes that

[474] EEI at 99.

[475] *See* NOPR at P 1140.

premature reliance on various tools that are now under development but not yet operational may jeopardize reliability by providing operators with a false sense of security and recommends leaving the decision to use such tools to NERC. EEI points out that any tools to conduct the analyses recommended by the Commission will require adjustments and modifications to improve their capabilities. Therefore, EEI recommends that the Commission consider its proposals regarding these standards as long-term industry objectives and of a lower priority than other Reliability Standards. In addition, it is unclear to EEI whether the proposed voltage stability assessments apply to steady-state or dynamic analyses, or whether these assessments are of a general nature. Since these analyses are technically complex and involve a broad range of assumptions regarding system configurations, EEI suggests that the Commission provide further guidance.

(b) Commission Determination

1876. In response to the concerns of APPA, SDG&E and EEI on the availability of tools, the Commission recognizes that transient voltage stability analysis is often conducted as an offline study, and that steady-state voltage stability analysis can be done online. The Commission clarifies that it does not wish to require anyone to use tools that are not validated for real-time operations. Taking these comments into consideration, the Commission clarifies its proposed modification from the NOPR. For the Final Rule, we direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR–001–1 to include Requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations. The ERO should consider the available technologies and software as it develops this modification to VAR–001–1 and identify a process to assure that the Reliability Standard is not limiting the application of validated software or other tools.

1877. With respect to MidAmerican's suggestion of exempting areas that are not susceptible to voltage instability from the requirement to perform voltage stability analysis, the Commission notes that such exemption is not appropriate. We draw an analogy between transient stability limits and voltage stability limits. The requirement to perform voltage stability analysis is similar to existing operating practices for IROLs that are dictated by transient stability. Transient stability IROLs are determined using the results of off-line simulation studies, and no areas are exempt. In real-time operations, these IROLs are monitored to ensure that they are not violated. Similarly, voltage stability is conducted in the same manner, determining limits with off-line tools and monitoring limits in real-time operations. Areas that are susceptible to voltage instability are expected to run studies frequently, and areas that have not been susceptible to voltage instability are expected to periodically update their study results to ensure that these limits are not encountered during real-time operations.

v. Controllable Load

(a) Comments

1878. SMA supports adoption of the proposal to include controllable load as a reactive resource. SMA notes that its members' facilities often include significant capacitor banks, and further, reducing load can reduce local reactive requirements.

1879. SoCal Edison suggests caution regarding the Commission's proposal to include controllable load as a reactive resource. It agrees that, when load is reduced, voltage will increase and for that reason controllable load can lessen the need for reactive power. However, SoCal Edison believes that controllable load is typically an energy product and there are other impacts not considered by the Commission's proposal to include controllable load as a reactive resource. For example, activating controllable load for system voltage control lessens system demand, requiring generation to be backed down. It is not clear to SoCal Edison whether any consideration has been given to the potential reliability or commercial impacts of the Commission's proposal.

(b) Commission Determination

1880. The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system.[476] Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR–001–1. While we affirm this requirement, we expect the ERO to consider the comments of SoCal Edison with regard to reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards.

vi. Summary of Commission Determination

1881. Accordingly, the Commission approves Reliability Standard VAR–001–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to VAR–001–1 through the Reliability Standards development process that: (1) Expands the applicability to include reliability coordinators and LSEs; (2) includes detailed and definitive requirements on ''established limits'' and ''sufficient reactive resources'' as discussed above, and identifies acceptable margins above the voltage instability points; (3) includes Requirements to perform voltage stability analysis periodically, using online techniques where commercially available and offline techniques where online techniques are not available, to assist real-time operations, for areas susceptible to voltage instability; (4) includes controllable load among the reactive resources to satisfy reactive requirements and (5) addresses the power factor range at the interface between LSEs and the transmission grid.

b. VAR–002–1

1882. Reliability Standard VAR–002–1 requires generator operators to operate in automatic voltage control mode, to maintain generator voltage or reactive power output as directed by the transmission operator, and to notify the transmission operator of a change in status or capability of any generator reactive power resource. The Reliability Standard requires generator owners to provide transmission operators with settings and data for generator step-up transformers. In the NOPR, the Commission stated its belief that Reliability Standard VAR–002–1 is just, reasonable, not unduly discriminatory or preferential and in the public interest; and proposed to approve it as mandatory and enforceable.

i. Comments

1883. APPA and SDG&E agree that VAR–002–1 is sufficient for approval as a mandatory and enforceable Reliability Standard.

1884. Dynegy believes that VAR–002–1 should be modified to require more detailed and definitive requirements when defining the time frame associated with an ''incident'' of non compliance (*i.e.*, each 4-second scan, 10-minute

[476] *See* FERC Staff Report, *Principles of Efficient and Reliable Reactive Power Supply and Consumption* (2005), available at *http://www.ferc.gov/legal/staff-reports.asp.*

integrated value, hourly integrated value). Dynegy states that, as written, this Reliability Standard does not define the time frame associated with an ''incident'' of non-compliance, but apparently leaves this decision to the transmission operator. Dynegy believes that either more detail should be added to the Reliability Standard to cure this omission, or the Reliability Standard should require the transmission operator to have a technical basis for setting the time frame that takes into account system needs and any limitations of the generator. Dynegy believes that this approach will eliminate the potential for undue discrimination and the imposition of overly conservative or excessively wide time frame requirements, both of which could be detrimental to grid reliability.

ii. Commission Determination

1885. In the NOPR, the Commission commended NERC and industry for its efforts in expanding on the Requirements of VAR–002–1 from the predecessor standard, and noted that the submitted Reliability Standard includes Measures and Levels of Non-Compliance to ensure appropriate generation operation to maintain network voltage schedules. Accordingly, the Commission approves Reliability Standard VAR–002–1 as mandatory and enforceable.

1886. Dynegy has suggested an improvement to Reliability Standard VAR–002–1, and NERC should consider this in its Reliability Standards development process.

14. Glossary of Terms Used in Reliability Standards

1887. NERC's glossary is updated whenever a new or revised Reliability Standard is approved that includes a new defined term. The glossary may also be approved by a separate action using NERC's Reliability Standards development process. NERC updated the glossary in its August 28, 2006 Supplemental Filing.

1888. In the NOPR, the Commission proposed to approve the glossary. In addition, the Commission proposed to direct NERC to submit a modification to the glossary that: (1) Includes the statutory definitions of Bulk-Power System, Reliable Operation, and Reliability Standard, as set forth in section 215(a) of the FPA; (2) modifies the definitions of ''transmission operator'' and ''generator operator'' to include aspects unique to ISOs, RTOs and pooled resource organizations; (3) modifies the definition of ''bulk electric system'' consistent with discussion in the NOPR Common Issues section [477] and (4) modifies the definition of terms concerning reserves (such as operating reserves) to include DSM, including controllable load.

a. Comments

1889. NERC supports the Commission's proposal to approve the glossary. APPA supports the Commission's proposal to have NERC incorporate the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard into the NERC glossary, as an aide to the development of future NERC Reliability Standards.

1890. APPA suggests that the Commission permit NERC and industry to consider whether any modifications to the terms ''transmission operator'' and ''generation operator'' are needed, rather than directing NERC to modify these terms. APPA's initial reaction is that the existing terms are adequate and accommodate most elements of ISO, RTO and pooled resource organization operations. APPA believes that a broader and continuing inquiry is required to address such situations. APPA anticipates that many such concerns will arise as NERC and the Regional Entities implement the initial compliance program in June 2007, and states that any additional changes to the glossary should be driven by that experience.

1891. APPA's concerns regarding the Commission proposal to modify the definition of terms concerning reserves to include DSM (including controllable load) are discussed above in reference to the BAL Reliability Standards.

1892. NERC supports the Commission's proposal to direct NERC to complete the necessary improvements to the proposed Reliability Standards through the established NERC Reliability Standards development process.

1893. Santa Clara submits that, to eliminate any ambiguity about when these definitions of these commonly-used terms apply, a footnote should be added to the glossary that states that the definitions contained in the glossary are not intended to supersede any definitions in a tariff or contract approved or accepted by the Commission.

b. Commission Conclusion

1894. The Commission approves the glossary. The terms defined in the glossary have an important role in establishing consistent understanding of the Reliability Standards Requirements and implementation. The approval of the glossary will provide continuity in application of the glossary definitions industry-wide, and will eliminate multiple interpretations of the same term or function, which may otherwise create miscommunication and jeopardize Bulk-Power System reliability. The glossary should be updated through the Reliability Standards development process whenever a new or revised Reliability Standard that includes a new defined term is approved, or as needed to clarify compliance activities. For example, the ERO will need to update the glossary to reflect modifications required by the Commission in this Final Rule.[478]

1895. The Commission directs the ERO to modify the glossary through the Reliability Standards development process to include the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard. However, this determination does not negate our discussion in the Applicability section of the Final Rule. While the glossary should be revised to include the stautory definition of Bulk-Power System, the Reliability Standards refer to the bulk electric system, which is also defined in the glossary.

1896. The Commission directs the ERO to submit a modification to the glossary that enhances the definitions of ''transmission operator'' and ''generator operator'' to reflect concerns of the commenters and the direction provided by the Commission in other sections of this Final Rule. The Commission is concerned that there not be any gaps or unecessary overlaps of responsibilities concerning any of the Requirements in the Reliability Standards that are applicable to transmission operators and generator operators.

1897. Further, we adopt the NOPR proposal to require the ERO to submit a modification to the glossary that updates the definition of ''operating reserves,'' as required in our discussion of BAL–002–0 and BAL–005–0.

1898. Regarding Santa Clara's concern about terms in the glossary differing from definitions in tariffs, we clarify that the glossary governs Reliability Standards, while tariff definitions govern tariff issues. We recognize that many items have different tariff definitions from those in the NERC glossary. However, we expect most of these terms to be consistent. If the glossary definition creates a conflict between the Reliability Standards and a Transmission Organization's function,

[477] NOPR at P 42–43.

[478] *See, e.g.*, MOD–001–0, TOP–002–1 and the INT Reliability Standards.

rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by the Commission, then the Transmission Organization shall expeditiously notify the Commission, the Electric Reliability Organization and the relevant Regional Entity of the possible conflict pursuant to § 39.6 of the Commission's regulations.[479]

1899. In conclusion, the Commission approves the glossary. Further, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs ERO to modify the glossary through the Reliability Standards development process to: (1) Include the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard; (2) modify the definition of ''transmission operator'' and ''generator operator'' to include aspects unique to ISO, RTO and pooled resource organizations and (3) modify the definition of ''operating reserves'' as discussed in BAL–002–0 and BAL–005–0.

III. Information Collection Statement

1900. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[480] The information collection requirements in this Final Rule are identified under the Commission data collection, FERC–725A ''Bulk Power System Mandatory Reliability Standards.'' Under section 3507(d) of the Paperwork Reduction Act of 1995,[481] the proposed reporting requirements in the subject rulemaking will be submitted to OMB for review. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 (Attention: Michael Miller, Office of the Executive Director, 202–502–8415) or from the Office of Management and Budget (Attention: Desk Officer for the Federal Energy Regulatory Commission, fax: 202–395–7285, e-mail: *oira_submission@omb.eop.gov*).

1901. The ''public protection'' provisions of the Paperwork Reduction Act of 1995 requires each agency to display a currently valid control number and inform respondents that a response is not required unless the information collection displays a valid OMB control number on each information collection or provides a justification as to why the information collection number cannot be displayed. In the case of information collections published in regulations, the control number is to be published in the **Federal Register**.

1902. *Public Reporting Burden:* In the NOPR, the Commission based its initial estimates on the premise that the proposed Reliability Standards have already been in effect for a substantial period of time on a voluntary basis and consequently entities would have already put them into practice. Seventy of the 125 commenters express concern with the burden to be imposed by the NOPR's requirements. The majority of these comments address the potential impact the requirements would have on small entities but did not provide specific estimates on this impact. Because these comments are also the subject of the analysis performed under the Regulatory Flexibility Act, the Commission has provided a response under that section of this rulemaking. Commenters also raise concerns about the impact of specific Reliability Standards, and the Commission has addressed those concerns in the discussion of each Reliability Standard. Five commenters, Reliant, TAPS, Wisconsin Electric, Portland General and WECC questioned the Commission's initial burden estimates as contained in the NOPR.

1903. By Reliant's estimate, it would take at least four employees to prepare and submit compliance filings and to monitor compliance on an on-going basis. TAPS, while not providing a specific estimate on the burden, believes that the NOPR's proposed application of mandatory Reliability Standards is overly-broad and would encompass several thousand municipal systems. Wisconsin Electric states that the NOPR significantly understated the impact that would be imposed by mandatory Reliability Standards. Wisconsin Electric believes that a ''typical control area utility with its multiple functional entity responsibilities'' will need far more than the 100 hours estimated by the Commission to manage a quality compliance program as discussed in the ERO's Sanction Guidelines.[482]

1904. Portland General believes that meeting the Requirements of mandatory Reliability Standards will place an additional burden for documentation, over and above compliance with the substance of the Requirements. It claims that the NOPR failed to take this additional burden into account in its cost estimate for compliance. WECC disagrees with the Commission's estimate that compliance cost would be $40 million annually on an aggregate basis. It also disagrees with the Commission's assumption that there would be no increased reporting burden or additional information requirements because the Reliability Standards impose new documentation requirements that will create additional costs.

1905. In response to the comments and upon further review we have revised our initial estimates as reflected in the table below. While the ERO has submitted several new Reliability Standards and included additional Measures for documenting compliance with 20 existing Reliability Standards, we continue to believe that the reporting requirements embedded in the Reliability Standards that are approved in the Final Rule have been implemented on a voluntary basis for many years in most instances.[483] This would not apply, however, to entities that are new to reliability oversight. We encourage entities that are responsible for compliance with mandatory Reliability Standards to develop a quality compliance program as discussed in the ERO's Sanction Guidelines. However, we believe that the costs of such a program are distinct from the reporting burdens that are estimated below.

1906. Further, our estimates below reflect a revision in the number of respondents, based on our determinations regarding ''applicability,'' as discussed in section II.C above.

1907. *Total Annual Hours for Collection:*

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
FERC–725A				
Investor Owned Utilities	170	1	2,080	353,600
Municipals and Cooperatives—Large	80	1	1,420	113,600
Municipals and Cooperatives—Small	670	1	710	475,700
Generator Operators	360	1	500	180,000

[479] 18 CFR 39.6 (2006).

[480] 5 CFR 1320.11.

[481] 44 U.S.C. 3507(d) (2000).

[482] Wisconsin Electric at 9.

[483] NOPR at P 1157.

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
Power Marketers	159	1	100	15,900
Recordkeeping	Investor Owned Utilities			35,360
	Munis/Coops (Large)			11,360
	Munis/Coops (Small)			47,570
	Generator Owner/Ops.			18,000
	Power Marketers			1,590
Totals				1,252,680

(FTE=Full Time Equivalent or 2,080 hours)

Total Hours = 1,138,800 (reporting) + 113,880 (recordkeeping) = 1,252,680 hours. This estimated reporting burden will be significantly reduced once joint action agencies are established, which will reduce the number of small entities that will be responsible for compliance with Reliability Standards.

1908. *Information Collection Costs:* The Commission sought comments about the costs needed to comply with these requirements. As noted above, a number of commenters state that the NOPR underestimated the burden of the rulemaking in terms of hours required to comply. However, no comments were received regarding the Commission's estimate of the projected cost of $200/hour to comply with these requirements. In further consideration, the Commission believes that the $200/hour projection is too high, and the calculations below reflect an adjusted hourly figure.

Cost to Comply:

Reporting = 1,138,800 @ $114/hour = $129,823,200

1,138,800 hours @ $114 per hour (average cost of attorney ($200 per hour), consultant ($150), technical ($80) and administrative support ($25)).

Recordkeeping = 113,880 @ $17/hour = $1,935,960

113,880 hours @ $17 per hour (file/record clerk @ $17 an hour)

Total Costs: Reporting ($129,823,200) + Recordkeeping ($1,935,960) = $131,759,160.

Sources: ''NERC Compliance Update: What it might cost to comply'', Herb Schrayshuen, NARUC-Electric Reliability Staff Subcommittee, November 12, 2006.

Janco Associates, Inc., 2005 Information Technology Compensation Study, January 2005.

Bureau of Labor Statistics, Department of Labor, Occupational Outlook Handbook, *http://www.bls.gov/oco/ocos268.htm.*

Titles: FERC–725A ''Mandatory Reliability Standards for the Bulk-Power System''.

Action: Proposed Collection of Information.

OMB Control Nos: To be determined.

Respondents: Business or other for profit, not for profit institutions, state, local or tribal government and Federal Government.

Frequency of Responses: On occasion.

Necessity of Information: The Final Rule approves 83 Reliability Standards. Compliance with such Reliability Standards will be mandatory and enforceable for the applicable categories of entities identified in each Reliability Standard. These Reliability Standards are approved by the Commission pursuant to its authority under section 215 of the FPA, which authorizes the Commission to approve a Reliability Standard proposed by the ERO if the Commission determines that it is just and reasonable, not unduly discriminatory or preferential and in the public interest. The Reliability Standards approved in this Final Rule are necessary for the reliable operation of the nation's interconnected Bulk-Power System.

For information on the requirements, submitting comments on the collection of information and the associated burden estimates including suggestions for reducing this burden, please send your comments to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 (Attention: Michael Miller, Office of the Executive Director, 202–502–8415) or send comments to the Office of Management and Budget (Attention: Desk Officer for the Federal Energy Regulatory Commission, fax: 202–395–7285, e-mail *oira_submission@omb.eop.gov*).

IV. Environmental Analysis

1909. 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.[484] The actions taken here fall within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.[485]

V. Regulatory Flexibility Act

1910. The Regulatory Flexibility Act of 1980 (RFA)[486] generally requires a description and analysis of Final Rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

1911. In drafting a rule an agency is required to: (1) Assess the effect that its regulation will have on small entities; (2) analyze effective alternatives that may minimize a regulation's impact and (3) make the analyses available for public comment.[487] In its NOPR, the agency must either include an initial regulatory flexibility analysis (initial RFA) [488] or certify that the proposed rule will not have a ''significant impact on a substantial number of small entities.'' [489]

1912. If in preparing the NOPR an agency determines that the proposal could have a significant impact on a substantial number of small entities, the agency shall ensure that small entities will have an opportunity to participate in the rulemaking procedure.[490]

1913. In its Final Rule, the agency must also either prepare a Final Regulatory Flexibility Analysis (Final RFA) or make the requisite certification. Based on the comments the agency receives on the NOPR, it can alter its original position as expressed in the NOPR but it is not required to make any substantive changes to the proposed regulation.

1914. The statute provides for judicial review of an agency's final certification or Final RFA.[491] An agency must file a

[484] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47,897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[485] 18 CFR 380.4(a)(5).

[486] 5 U.S.C. 601–612 (2006).

[487] 5 U.S.C. 601–604.

[488] 5 U.S.C. 603(a).

[489] 5 U.S.C. 605(b).

[490] 5 U.S.C. 609(a).

[491] 5 U.S.C. 611.

Final RFA demonstrating a ''reasonable, good-faith effort'' to carry out the RFA mandate.[492] However, the RFA is a procedural, not a substantive, mandate. An agency is only required to demonstrate a reasonable, good faith effort to review the impact the proposed rule would place on small entities, any alternatives that would address the agency's and small entities' concerns and their impact, provide small entities the opportunity to comment on the proposals, and review and address comments. An agency is not required to adopt the least burdensome rule. Further, the RFA does not require an agency to assess the impact of a rule on all small entities that may be affected by the rule, only on those entities that the agency directly regulates and that will be directly impacted by the rule.[493]

A. Notice of Proposed Rulemaking

1915. In the NOPR, the Commission stated that the proposed Reliability Standards ''may cause some small entities to experience significant economic impact.'' [494] In response to the ERO's proposal to develop limits on the applicability of specific Reliability Standards, the Commission stated that, while it could not rule on the merits until a specific proposal is submitted, the Commission stated that it believed that reasonable limits based on size may be an acceptable alternative to ''lessen the economic impact on the proposed rule on small entities.'' [495] The Commission emphasized that any such limits must not weaken Bulk-Power System reliability.

1916. Further, under the Applicability Issues section of the NOPR, we devoted an entire subsection to the issues facing small entities.[496] The Commission stated that there may be instances in which small entity compliance with a particular Reliability Standard may be critical to reliability. It explained that, in such circumstances, it may be appropriate to differentiate among subsets of users, owners and operators. As an example, the NOPR provided that ''the requirement to have adequate communications capabilities to address real-time emergency conditions * * * may be necessary for all applicable entities regardless of size or role, although we understand that the implementation of these requirements for applicable entities may vary based on size or role.'' [497] Additionally, in the NOPR, the Commission supported the ERO's proposal to permit the registration of ''joint action agencies,'' a concept designed to ease the burden of small entities by allowing one organization to perform reliability-related activities for multiple entities. The Commission proposed to direct the ERO to develop procedures that would permit a joint action agency or similar organization to accept compliance responsibility on behalf of its members.

1917. Thus, in the NOPR, the Commission discussed the potential disparate impact on small entities, considered the implications and potential alternatives and solicited comments on the limiting the application of the Reliability Standards to small entities. Further, the Information Collection Statement discussed the difficulty estimating the number of small entities that would be affected by the Reliability Standards. As such, the Commission was aware of the potential impacts on small entities and was actively considering alternatives that would lessen the impact on them while still ensuring reliability of the Bulk-Power System.

1. Comments

1918. APPA and NRECA, in their joint comments, provide data about their membership. APPA states that, based on 2005 data, 1,971 public utilities or 98 percent of the public utilities in the United States had less than 4 million MW hours in sales which would qualify them as small entities. Of these, 90 percent—or 1,775—are distribution-only utilities, 48 are wholesale-only, and 148 make both wholesale and retail sales.[498] NRECA states that its membership includes 930 rural cooperatives most of which are distribution utilities and almost all of which would qualify as small entities. Additionally, according to NRECA, 40 of its 65 generation and transmission cooperatives also qualify as small entities.[499]

1919. APPA/NRECA contends that the Commission did not include a complete initial RFA analysis as required and, without a full initial RFA, the Commission cannot lay a proper foundation for eliciting public comments on the impacts of the rule on small entities. Specifically, APPA/NRECA contends that the NOPR failed to include proposals that would minimize the impact on small entities. They assert that, instead, the Commission's proposed definition of bulk electric system in the NOPR exceeds NERC's definition and thereby sweeps in many small facilities that are unnecessary to the Reliable Operation of the Bulk-Power System. APPA/NRECA argue that, if the Commission adopts this definition, many small transmission owners and operators of lower voltage transmission systems will be unnecessarily required to bear the increased training costs to comply with Reliability Standards, yet the NOPR never considered these additional burdens. APPA/NRECA also asserts that, under this definition, many small distribution providers would also be required to comply with the communication-related (COM) Reliability Standards at additional costs that were never discussed. They request that the Commission address these shortcomings.

1920. APPA/NRECA also claims that the Commission substantially underestimated the number of small entities that would be impacted by the application of the Reliability Standards as proposed in the NOPR. APPA/NRECA asserts that 98 percent of public utilities and 99 percent of public cooperatives, along with numerous small industrial facilities, small qualifying facilities and small generators would qualify under the small entity definition and would be impacted by the rule. According to APPA/NRECA, most of these small entities would not have a material impact on the reliability of the Bulk-Power System but, under the NOPR's definition of Bulk-Power System, would be required to comply with the Reliability Standards.

1921. APPA/NRECA suggests that the Commission can significantly reduce the impact on small entities by ''focusing on materiality.'' They contend that an overly-expansive reliability regime would violate the FPA by imposing unnecessary regulatory burdens on small entities and divert the ERO's and the Commission's resources away from those entities that are crucial to Bulk-Power System reliability. APPA/NRECA asserts that the Commission can ensure reliability without unnecessarily burdening small entities by considering two alternatives. First, they urge the Commission to adopt NERC's current definition of bulk electric system. Second, they ask the Commission to reconsider the standard-by-standard approach to defining owners, users and operators of the Bulk-Power System and, instead, accept the NERC compliance registry to identify the entities that will be responsible for compliance with Reliability Standards. APPA/NRECA, TAPS, and numerous

[492] *United Cellular Corp.* v. *FCC*, 254 F.3d 78, 88 (D.C. Cir. 2001); *Alenco Commuications, Inc.* v. *FCC*, 201 F.3d 608, 625 (5th Cir. 2000).

[493] *Mid-Tex Electric Coop., Inc.* v. *FERC*, 773 F.2d 327 (D.C. Cir 1985).

[494] NOPR at P 1175.

[495] *Id.* at 1176.

[496] *Id.* at 49–53 (Section B.3 ''Applicability to Small Entities'').

[497] *Id.* at 51.

[498] APPA/NRECA comments at 2.

[499] *Id.*

other commenters discuss these proposals in their comments, which the Commission addresses in the Applicability Issues section of the Final Rule.[500]

1922. TAPS asserts that the Commission should apply the ERO's registration thresholds and, ''absent such limits, the Commission cannot satisfy its obligations under the [RFA].'' [501] Georgia Cities asserts that the Commission should adopt reasonable limits on the application of the Reliability Standards to small entities, as it promised in its RFA statement.

2. Commission Response

1923. The Commission believes that the NOPR provided a meaningful discussion of the impact that the Reliability Standards could have on small entities and discussed several potential alternatives. In fact, the NOPR contained an entire section on the applicability of the proposed standards on small entities.[502] In that section, the Commission discussed various alternatives to lessen the acknowledged potential impact on small entities. The Commission indicated its receptiveness to the ERO's proposal to develop threshold limits regarding the applicability of specific Reliability Standards. The Commission also suggested that, where it is necessary for reliability that a Reliability Standard apply to small entities, implementation of the requirements of such Reliability Standards may vary based on size or role. In the NOPR, the Commission set forth another alternative to address the potential burden on small entities when it proposed to direct the ERO to develop procedures permitting a joint action agency or similar organization to accept compliance responsibility on behalf of its members.

1924. As previously stated, the purpose of the RFA is to ensure that agencies consider the impact a proposed rule would have on small entities and any potential alternatives that would minimize that impact. The initial RFA analysis is designed to elicit informed comments on the impacts to small entities and alternatives. The Commission believes the NOPR achieved this goal. After the NOPR was issued, the Commission received over 125 comments and a majority of those addressed small entity issues. Further, almost all of the commenters addressed the NOPR's proposed interpretation of the definition of the bulk electric system, which as APPA/NRECA states would have had the greatest impact on small entities.

1925. In addition to the comments received addressing these issues, Commission staff has met with representatives of small entities, including APPA and NRECA, and listened to their concerns on the potential impacts of the Final Rule and discussed possible alternatives.

1926. Since receiving APPA/NRECA's comments on the RFA, the Commission has compiled and reviewed available data on small entities and the impact of the Final Rule on such entities. Therefore, the Commission believes that any inadequacy that may have existed in the NOPR's initial RFA analysis has now been corrected. This Final RFA and the alternative proposals adopted herein demonstrate the Commission's consideration of the potential burdens that the rulemaking could place on small entities.

1927. As discussed in the Applicability section above, the Commission adopts in the Final Rule the current definition of bulk electric system. Any possible change to the definition would occur in a future Commission proceeding. Further, the Commission has endorsed the ERO's compliance registry process to identify the entities that must comply with mandatory Reliability Standards.[503] By adopting these alternative proposals, the Commission has been responsive to small entity concerns and greatly reduced the number of small entities that will be affected by the Final Rule.

B. Final RFA

1. Description of the Reasons Why Action by the Agency Is Being Considered

1928. On April 4, 2006, as later modified and supplemented, NERC—the ERO—submitted 107 Reliability Standards for Commission approval pursuant to section 215(d) of the FPA. The ERO's submission includes the ''Version 0'' standards with which the electric industry has complied on a voluntary basis as well as several new Reliability Standards approved by NERC since its certification as the ERO.

1929. As set forth in section 215(a) of the FPA, the term ''Reliability Standard'' means a requirement, approved by the Commission to provide for the Reliable Operation of the Bulk-Power System. The term ''Reliable Operation'' means ''operating the elements of the bulk-power system within equipment and electric system, thermal, voltage, and stability limits so that instability, uncontrolled, or cascaded failures of such system will not occur as a result of a sudden disturbance * * * or unanticipated failure of system elements.'' [504] Thus, the purpose of each Reliability Standard approved by the Commission in this Final Rule is to provide for the Reliable Operation of the Bulk-Power System and thereby minimize the risk of instability, uncontrolled or cascading failure on the Bulk-Power System.

1930. The Commission is approving 83 of the proposed Reliability Standards. Upon the effective date of the Final Rule, compliance with these Reliability Standards will be mandatory and enforceable for applicable users, owners and operators of the Bulk-Power System. The Commission believes that these Reliability Standards form a solid foundation on which to develop and maintain the reliability of the North American Bulk-Power System.

2. Objectives of and the Legal Basis for the Final Rule

1931. This Final Rule requires applicable users, owners and operators of the Bulk-Power System to comply with mandatory and enforceable Reliability Standards. As discussed above, these Reliability Standards are necessary to ensure the reliable operation of the North American Bulk-Power System.

1932. EPAct 2005 added a new section 215 to the FPA, which provides for a system of mandatory and enforceable Reliability Standards. Section 215(d)(1) of the FPA provides that the ERO must file each Reliability Standard or modification to a Reliability Standard that it proposes to be made effective, *i.e.*, mandatory and enforceable, with the Commission. As mentioned above, on April 4, 2006, and as later modified and supplemented, the ERO submitted 107 Reliability Standards for Commission approval pursuant to section 215(d) of the FPA.

1933. Section 215(d)(2) of the FPA provides that the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a proposed Reliability Standard if it meets the statutory standard for approval, giving due weight to the technical expertise of the ERO. Alternatively, the Commission may remand a Reliability Standard pursuant to section 215(d)(4) of the FPA. Further, the Commission may order the ERO to submit to the

[500] *See* Applicability Issues: Bulk-Power System v. Bulk Electric System and Applicability to Small Entities, *supra* sections II.C.1–2.

[501] TAPS at 13.

[502] NOPR at P 49–53.

[503] As noted previously, APPA, NRECA and TAPs submitted supplemental comments supporting the ERO's compliance registry process.

[504] 16 U.S.C. 824o(a)(4) (2006).

Commission a proposed Reliability Standard or a modification to a Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Reliability Standard appropriate to ''carry out'' section 215 of the FPA.[505] The Commission's action in this Final Rule is based on its authority pursuant to section 215 of the FPA.

3. Significant Issues Raised by Comments, Agency Assessment of the Comments and a Statement of Any Changes Made in the Proposed Rule as a Result of the Comments

1934. Numerous small entity commenters oppose the NOPR interpretation of bulk electric system and urge the Commission to adopt the ERO's current definition of that term. Further, small entity commenters oppose the NOPR's proposal to address applicability on a standard-by-standard basis and, instead, ask that the Commission rely on the ERO's compliance registry process as the means to identify entities responsible for complying with mandatory and enforceable Reliability Standards. Commenters assert that the Commission's proposed changes would greatly increase the number of small entities that would be significantly impacted by the Final Rule.

1935. As discussed above, the Commission is not adopting its proposed interpretation of bulk electric system contained in the NOPR. Rather, the Commission adopts the NERC definition of bulk electric system. Further, the Commission is relying on NERC's registration process to provide as much certainty as possible regarding the applicability and responsibility of specific entities in the start-up phase of the mandatory Reliability Standards regime. Any change in these approaches would be addressed in a separate Commission proceeding.

1936. A complete summary of these comments and the Commission's response has been previously addressed in the Applicability section.

4. Description and Estimate of the Number of Small Entities To Which the Final Rule Will Apply

1937. According to the SBA, a small electric utility is defined as one that has a total electric output of less than four million MWh in the preceeding year.

1938. According to the DOE's Energy Information Administration (EIA), there were 3,284 electric utility companies in the United States in 2005,[506] and 3,029 of these electric utilities qualify as small entities under the SBA definition. Of these 3,284 electric utility companies, the EIA subdivides them as follows: (1) 883 cooperatives of which 852 are small entity cooperatives; (2) 1,862 municipal utilities, of which 1842 are small entity municipal utilities; (3) 127 political subdivisions, of which 114 are small entity political subdivisions; (4) 159 power marketers, of which 97 individually could be considered small entity power marketers; [507] (5) 219 privately owned utilities, of which 104 could be considered small entity private utilities; (6) 25 state organizations, of which 16 are small entity state organizations and (7) nine federal organizations of which four are small entity federal organizations.

1939. As discussed above, the Commission is relying on the ERO's compliance registry process to identify which entities must comply with mandatory and enforceable Reliability Standards. The ERO's Compliance Registry Criteria describe how NERC will identify organizations that may be candidates for registration and assign them to the compliance registry.[508] According to this document, the ERO will register transmission owners and operators with an integrated element associated with the Bulk-Power System of 100 kV and above, or lower voltage as defined by a Regional Entity. The ERO plans to register only those distribution providers or LSEs that have a peak load of 25 MW or greater and are directly connected to the bulk electric system *or* are designated as a responsible entity as part of a required underfrequency load shedding program or a required undervoltage load shedding program. For generators, the ERO plans to register individual units of 20 MVA or greater that are directly connected to the bulk electric system, generating plants with an aggregate rating of 75 MVA or greater, any blackstart unit material to a restoration plan, or any generator ''regardless of size, that is material to the reliability of the Bulk-Power System.'' Further, the ERO will not register an entity that meets the above criteria if it has transferred responsibility for compliance with mandatory Reliability Standards to a joint action agency or other organization.

1940. As mentioned above, the SBA defines a small electric utility as one that has a total electric output of less than four million MWh in the proceeding year. Thus, the set of small entities that must comply with mandatory Reliability Standards would be those that exceed the ERO registry criteria but still meet the SBA definition. The Commission has reviewed data compiled by EIA in Form EIA–861, NERC's pre-registry data, and information submitted by commenters, and determined an estimate of the number of small entities to which the Final Rule will apply.

1941. The Commission estimates that the Reliability Standards approved in the Final Rule will apply to approximately 682 small entities (excluding entities in Alaska and Hawaii) as follows: 670 small municipal utilities and cooperatives and 12 small investor-owned utilities.

1942. As discussed above, the ERO's Compliance Registry Criteria allows for a joint action agency, G&T cooperative or similar organization to accept compliance responsibility on behalf of its members. Once such organizations register with the ERO, the number of small entities registered with the ERO will diminish and, thus, significantly reduce the impact of the Final Rule on small entities.

1943. To be included in the compliance registry, the ERO will have made a determination that a specific small entity has a material impact on the Bulk-Power System. Consequently, the compliance of such small entities is justifiable as necessary for Bulk-Power System reliability.

5. Description of the Projected Reporting, Recordkeeping and Other Compliance Requirements for Small Entities

1944. A complete summary of comments and the Commission's response has been previously addressed in the Information Collection Statement section.

6. Duplication of Other Federal Rules

1945. There are no relevant Federal rules which may duplicate, overlap or conflict with the Final Rule.

7. Description of Any Significant Alternatives to the Final Rule

1946. In the Final Rule, the Commission adopts several significant alternatives that will minimize the burden on small entities. The Commission approves the current ERO definition of bulk electric system, which

[505] *See* 16 U.S.C. 824o(d)(5) (2006).

[506] *See* Energy Information Administration Database, Form EIA–861, Dept. of Energy (2005), available at *http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.*

[507] Most of these small entity power marketers and private utilities are affiliated with others and, therefore, do not qualify as small entities under the SBA definition.

[508] *See* NERC Statement of Compliance Registry Criteria (Revision 3) at 6–8.

will reduce significantly the number of small entities responsible for complying with the Final Rule. The Commission also approves the ERO compliance registry process to identify the entities responsible for compliance with mandatory and enforceable Reliability Standards. Further, the Commission directs the ERO to submit a procedure to permit a joint action agency or similar organization to accept compliance responsibility on behalf of its members. A complete summary of comments and the Commission's response has been previously addressed in the Applicability Section.

VI. Document Availability

1947. 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 FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington DC 20426.

1948. From FERC'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.

1949. User assistance is available for eLibrary and FERC's Web site during normal business hours from our Help line at (202) 502–8222 or the Public Reference Room at (202) 502–8371 Press 0, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

VII. Effective Date and Congressional Notification

1950. These regulations are effective June 4, 2007. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule 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 40

Electric power; reporting and recordkeeping requirements.

By the Commission.

Philis J. Posey,

Acting Secretary.

■ In consideration of the foregoing, the Commission amends Chapter I, Title 18, *Code of Federal Regulations,* by adding Part 40 to read as follows:

PART 40—MANDATORY RELIABILITY STANDARDS FOR THE BULK-POWER SYSTEM

Sec.

40.1 Applicability.
40.2 Mandatory Reliability Standards.
40.3 Availability of Reliability Standards.

Authority: 16 U.S.C. 824o.

§ 40.1 Applicability.

(a) This part applies to all users, owners and operators of the Bulk-Power System within the United States (other than Alaska or Hawaii), including, but not limited to, entities described in section 201(f) of the Federal Power Act.

(b) Each Reliability Standard made effective by § 40.2 must identify the subset of users, owners and operators of the Bulk-Power System to which a particular Reliability Standard applies.

§ 40.2 Mandatory Reliability Standards.

(a) Each applicable user, owner or operator of the Bulk-Power System must comply with Commission-approved Reliability Standards developed by the Electric Reliability Organization.

(b) A proposed modification to a Reliability Standard proposed to become effective pursuant to § 39.5 of this Chapter will not be effective until approved by the Commission.

§ 40.3 Availability of Reliability Standards.

The Electric Reliability Organization must post on its Web site the currently effective Reliability Standards as approved and enforceable by the Commission. The effective date of the Reliability Standards must be included in the posting.

Note: The following appendices will not be published in the *Code of Federal Regulations.*

APPENDIX A.—DISPOSITION OF RELIABILITY STANDARDS, GLOSSARY AND REGIONAL DIFFERENCES

Reliability standard	Title	Proposed disposition
BAL–001–0	Real Power Balancing Control Performance	Approve.
BAL–002–0	Disturbance Control Performance	Approve; direct modification.
BAL–003–0	Frequency Response and Bias	Approve; direct modification.
BAL–004–0	Time Error Correction	Approve; direct modification.
BAL–005–0	Automatic Generation Control	Approve; direct modification.
BAL–006–1	Inadvertent Interchange	Approve; direct modification.
CIP–001–1	Sabotage Reporting	Approve; direct modification.
COM–001–1	Telecommunications	Approve; direct modification.
COM–002–2	Communications and Coordination	Approve; direct modification.
EOP–001–0	Emergency Operations Planning	Approve; direct modification.
EOP–002–2	Capacity and Energy Emergencies	Approve; direct modification.
EOP–003–1	Load Shedding Plans	Approve; direct modification.
EOP–004–1	Disturbance Reporting	Approve; direct modification.
EOP–005–1	System Restoration Plans	Approve; direct modification.
EOP–006–1	Reliability Coordination—System Restoration	Approve; direct modification.
EOP–007–0	Establish, Maintain, and Document a Regional Blackstart Capability Plan.	Pending.
EOP–008–0	Plans for Loss of Control Center Functionality	Approve; direct modification.
EOP–009–0	Documentation of Blackstart Generating Unit Test Results	Approve.
FAC–001–0	Facility Connection Requirements	Approve.
FAC–002–0	Coordination of Plans for New Facilities	Approve; direct modification.
FAC–003–1	Transmission Vegetation Management Program	Approve; direct modification.
FAC–004–0	Methodologies for Determining Electrical Facility Ratings	Withdrawn.
FAC–005–0	Electrical Facility Ratings for System Modeling	Withdrawn.
FAC–008–1	Facility Ratings Methodology	Approve; direct modification.
FAC–009–1	Establish and Communicate Facility Ratings	Approve.
FAC–012–1	Transfer Capabilities Methodology	Pending.

APPENDIX A.—DISPOSITION OF RELIABILITY STANDARDS, GLOSSARY AND REGIONAL DIFFERENCES—Continued

Reliability standard	Title	Proposed disposition
FAC–013–1	Establish and Communicate Transfer Capabilities	Approve; direct modification.
INT–001–2	Interchange Transaction Tagging	Approve; direct modification.
INT–002–0	Interchange Transaction Tag Communication and Assessment	Withdrawn.
INT–003–2	Interchange Transaction Implementation	Approve.
INT–004–1	Interchange Transaction Modifications	Approve.
INT–005–1	Interchange Authority Distributes Arranged Interchange	Approve.
INT–006–1	Response to Interchange Authority	Approve; direct modification.
INT–007–1	Interchange Confirmation	Approve.
INT–008–1	Interchange Authority Distributes Status	Approve.
INT–009–1	Implementation of Interchange	Approve.
INT–010–1	Interchange Coordination Exceptions	Approve.
IRO–001–1	Reliability Coordination—Responsibilities and Authorities	Approve; direct modification.
IRO–002–1	Reliability Coordination—Facilities	Approve; direct modification.
IRO–003–2	Reliability Coordination—Wide Area View	Approve; direct modification.
IRO–004–1	Reliability Coordination—Operations Planning	Approve; direct modification.
IRO–005–1	Reliability Coordination—Current Day Operations	Approve; direct modification.
IRO–006–3	Reliability Coordination—Transmission Loading Relief	Approve; direct modification.
IRO–014–1	Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators.	Approve.
IRO–015–1	Notifications and Information Exchange Between Reliability Coordinators.	Approve.
IRO–016–1	Coordination of Real-time Activities Between Reliability Coordinators	Approve.
MOD–001–0	Documentation of TTC and ATC Calculation Methodologies	Pending; direct modification.
MOD–002–0	Review of TTC and ATC Calculations and Results	Pending.
MOD–003–0	Procedure for Input on TTC and ATC Methodologies and Values	Pending.
MOD–004–0	Documentation of Regional CBM Methodologies	Pending; direct modification.
MOD–005–0	Procedure for Verifying CBM Values	Pending.
MOD–006–0	Procedures for Use of CBM Values	Approve; direct modification.
MOD–007–0	Documentation of the Use of CBM	Approve; direct modification.
MOD–008–0	Documentation and Content of Each Regional TRM Methodology	Pending; direct modification.
MOD–009–0	Procedure for Verifying TRM Values	Pending.
MOD–010–0	Steady-State Data for Transmission System Modeling and Simulation	Approve; direct modification.
MOD–011–0	Regional Steady-State Data Requirements and Reporting Procedures	Pending; direct modification.
MOD–012–0	Dynamics Data for Transmission System Modeling and Simulation	Approve; direct modification.
MOD–013–1	RRO Dynamics Data Requirements and Reporting Procedures	Pending; direct modification.
MOD–014–0	Development of Interconnection-Specific Steady State System Models.	Pending; direct modification.
MOD–015–0	Development of Interconnection-Specific Dynamics System Models	Pending; direct modification.
MOD–016–1	Actual and Forecast Demands, Net Energy for Load, Controllable DSM.	Approve; direct modification.
MOD–017–0	Aggregated Actual and Forecast Demands and Net Energy for Load	Approve; direct modification.
MOD–018–0	Reports of Actual and Forecast Demand Data	Approve.
MOD–019–0	Forecasts of Interruptible Demands and DCLM Data	Approve; direct modification.
MOD–020–0	Providing Interruptible Demands and DCLM Data	Approve; direct modification.
MOD–021–0	Accounting Methodology for Effects of Controllable DSM in Forecasts	Approve; direct modification.
MOD–024–1	Verification of Generator Gross and Net Real Power Capability	Pending.
MOD–025–1	Verification of Generator Gross and Net Reactive Power Capability	Pending; direct modification.
PER–001–0	Operating Personnel Responsibility and Authority	Approve.
PER–002–0	Operating Personnel Training	Approve; direct modification.
PER–003–0	Operating Personnel Credentials	Approve; direct modification.
PER–004–1	Reliability Coordination—Staffing	Approve; direct modification.
PRC–001–1	System Protection Coordination	Approve; direct modification.
PRC–002–1	Define and Document Disturbance Monitoring Equipment Requirements.	Pending.
PRC–003–1	Regional Requirements for Analysis of Misoperations of Transmission and Generation Protection Systems.	Pending.
PRC–004–1	Analysis and Mitigation of Transmission and Generation Protection System Misoperations.	Approve.
PRC–005–1	Transmission and Generation Protection System Maintenance and Testing.	Approve; direct modification.
PRC–006–0	Development and Documentation of Regional UFLS Programs	Pending.
PRC–007–0	Assuring Consistency with Regional UFLS Program	Approve.
PRC–008–0	Underfrequency Load Shedding Equipment Maintenance Programs	Approve; direct modification.
PRC–009–0	UFLS Performance Following an Underfrequency Event	Approve.
PRC–010–0	Assessment of the Design and Effectiveness of UVLS Program	Approve; direct modification.
PRC–011–0	UVLS System Maintenance and Testing	Approve; direct modification.
PRC–012–0	Special Protection System Review Procedure	Pending.
PRC–013–0	Special Protection System Database	Pending.
PRC–014–0	Special Protection System Assessment	Pending.
PRC–015–0	Special Protection System Data and Documentation	Approve.
PRC–016–0	Special Protection System Misoperations	Approve.
PRC–017–0	Special Protection System Maintenance and Testing	Approve; direct modification.

APPENDIX A.—DISPOSITION OF RELIABILITY STANDARDS, GLOSSARY AND REGIONAL DIFFERENCES—Continued

Reliability standard	Title	Proposed disposition
PRC–018–1	Disturbance Monitoring Equipment Installation and Data Reporting	Approve.
PRC–020–1	Undervoltage Load Shedding Program Database	Pending.
PRC–021–1	Undervoltage Load Shedding Program Data	Approve.
PRC–022–1	Undervoltage Load Shedding Program Performance	Approve.
TOP–001–1	Reliability Responsibilities and Authorities	Approve; direct modification.
TOP–002–2	Normal Operations Planning	Approve; direct modification.
TOP–003–0	Planned Outage Coordination	Approve; direct modification.
TOP–004–1	Transmission Operations	Approve; direct modification.
TOP–005–1	Operational Reliability Information	Approve; direct modification.
TOP–006–1	Monitoring System Conditions	Approve; direct modification.
TOP–007–0	Reporting SOL and IROL Violations	Approve.
TOP–008–1	Response to Transmission Limit Violations	Approve.
TPL–001–0	System Performance Under Normal Conditions	Approve; direct modification.
TPL–002–0	System Performance Following Loss of a Single BES Element	Approve; direct modification.
TPL–003–0	System Performance Following Loss of Two or More BES Elements	Approve; direct modification.
TPL–004–0	System Performance Following Extreme BES Events	Approve; direct modification.
TPL–005–0	Regional and Interregional Self-Assessment Reliability Reports	Pending.
TPL–006–0	Assessment Data from Regional Reliability Organizations	Pending.
VAR–001–1	Voltage and Reactive Control	Approve; direct modification.
VAR–002–1	Generator Operations for Maintaining Network Voltage Schedules	Approve.
Glossary	Glossary of Terms Used in Reliability Standards	Approve; direct modification.
Regional Difference	BAL–001:ERCOT:CPS2	Approve; direct modification.
Regional Difference	BAL–006: MISO RTO inadvertent Interchange Accounting	Approve.
Regional Difference	BAL–006: MISO/SPP Financial Inadvertent Settlement	Approve.
Regional Difference	INT–001/4: WECC Tagging Dynamic Schedules and Inadvertent Payback.	Pending.
Regional Difference	INT–001/3:MISO Energy Flow Information	Approve.
Regional Difference	INT–003: MISO/SPP Scheduling Agent	Approve.
Regional Difference	INT–003: MISO Enhanced Scheduling Agent	Approve.
Regional Difference	IRO–006: PJM/MISO/SPP Enhanced Congestion Management	Pending.

APPENDIX B.—COMMENTERS ON NOTICE OF PROPOSED RULEMAKING

Abbreviation	Entity
Alberta ESO	Alberta Electric System Operator.
ALCOA	Alcoa, Inc. and Alcoa Power Generating Company.
Allegheny	Allegheny Power and Allegheny Energy Supply Company, LLC.
AMP Ohio	American Municipal Power—Ohio, Inc.
APPA	American Public Power Association.
APPA/NRECA	APPA/NRECA.
ATC	American Transmission Company, LLC.
Avista/Puget	Avista Corporation and Puget Sound Energy, Inc.
BPA	Bonneville Power Administration.
CAISO	California Independent System Operator Corporation.
California Cogernation	Cogeneration Association of California and the Energy Producers and Users Coalition.
California PUC	Public Utilities Commission of the State of California.
CEA	Canadian Electricity Association.
Cleveland Public Power	City of Cleveland, Division of Cleveland Public Power.
Comverge	Comverge, Inc.
Connecticut Attorney General*	Richard Blumenthal, Attorney General for the State of Connecticut.
Connecticut DPUC*	Connecticut Department of Public Utility Control.
Constellation	Constellation Energy Group.
Dominion	Dominion Resources Services, Inc.
Duke	Duke Energy Corporation.
Dynegy	Dynegy, Inc.
EEI	Edison Electric Institute.
ELCON	Electricity Consumers Resource Council.
Entergy	Entergy Services, Inc.
EPSA	Electric Power Supply Association.
ERCOT	Electric Reliability Council of Texas, Inc.
Fertilizer Institute	Fertilizer Institute.
FirstEnergy	FirstEnergy Service Company.
Georgia Cities	City of Acworth. City of Adel. City of Blakely. City of Cairo. City of Calhoun. City of Camilla. City of College Park.

APPENDIX B.—COMMENTERS ON NOTICE OF PROPOSED RULEMAKING—Continued

Abbreviation	Entity
	City of Commerce.
	City of Doerun.
	City of Douglas.
	City of East Point.
	City of Ellaville.
	City of Fairburn.
	City of Forsyth.
	City of Fort Valley.
	City of Grantville.
	City of Hogansville.
	City of Lafayette.
	City of Lagrange.
	City of Lawrenceville.
	City of Mansfield.
	City of Monticello.
	City of Moultrie.
	City of Norcross.
	City of Oxford.
	City of Palmetto.
	City of Quitman.
	City of Sanderville.
	City of Sylvester.
	City of Thomaston.
	City of Thomasville.
	City of Washington.
	City of West Point.
	Crisp County Power Commission.
	City of Whigham.
	Fitzgerald Water, Light and Bond Commission.
	Marietta Power and Water.
Georgia Operators	Georgia System Operators Corp.
International Transmission	International Transmission Company.
ISO/RTO Council	ISO/RTO Council.
ISO–NE	ISO New England, Inc.
KCP&L	Kansas City Power and Light Company.
LPPC	Large Public Power Council.
Manitoba	Manitoba Hydro.
Marshall Municipal Utility Group Massachusetts DTE	Massachusetts Department of Telecommunications and Energy.
MEAG Power	MEAG Power.
MidAmerican	MidAmerican Electric Operating Companies.
Mid-Continent	Mid-Continent Systems Group.
MISO–PJM	Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.
MRO	Midwest Reliability Organization.
NARUC	National Association of Regulatory Utility Commissioners.
National Grid	National Grid USA.
NCPA	Northern California Power Agency.
NERC	North American Electric Reliability Corp.
New England Conference of Public Utilities Commissioners*.	New England Conference of Public Utilities Commissioners, Inc.
New York Commission	New York State Public Service Commission.
New York Public Power	New York Association of Public Power.
New York TOs	New York Transmission Owners.
Nevada Companies	Nevada Power Company and Sierra Pacific Power Company.
Northeast Utilities	Northeast Utilities Service Company.
Northern Indiana	Northern Indiana Public Service Company.
Northwest Requirements Utilities	Northwest Requirements Utilities.
NPCC	Northeast Power Coordinating Council: Cross-Border Regional Entity, Inc.
NRC	United States Nuclear Regulatory Commission.
NRECA	National Rural Electric Cooperative Association.
NYSRC	New York State Reliability Council, LLC.
NY Major Consumers	Multiple Intervenors, an unincorporated association of approximately 55 large industrial, commercial and institutional end-use energy consumers with facilities in New York.
Ontario IESO	Ontario Independent Electricity System Operator.
Otter Tail	Otter Tail Power Company.
PG&E	Pacific Gas and Electric Company.
Portland General	Portland General Electric Company.
Process Electricity Committee	Process Gas Consumers Group Electricity Committee.
Progress Energy	Progress Energy, Inc.
ReliabilityFirst	ReliabilityFirst Corporation.
Reliant	Reliant Energy, Inc.

APPENDIX B.—COMMENTERS ON NOTICE OF PROPOSED RULEMAKING—Continued

Abbreviation	Entity
Santa Clara	City of Santa Clara, California.
SDG&E	San Diego Gas and Electric Company.
SERC	SERC Reliability Corporation.
Six Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.
SMA	Steel Manufacturers Association.
Small Entities Forum	ReliabilityFirst Corporation Small Entities Forum.
SoCal Edison	Southern California Edison Company.
South Carolina E&G	South Carolina Electric and Gas Company.
Southern	Southern Company Services, Inc.
Southwest TDUs	Southwest Transmission Dependent Utility Group.
STI Capital	STI Capital Company.
Tacoma	Tacoma Power.
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
TVA	Tennessee Valley Authority.
Utah Municipal Power	Utah Associated Municipal Power Systems.
Valley Group	The Valley Group, Inc.
WECC	Western Electricity Coordinating Council.
WIRAB advice	Western Interconnection Regional Advisory Body.
Wisconsin Electric	Wisconsin Electric Power Company.
Xcel	Xcel Energy Services.

*Comments filed out-of-time.

APPENDIX C: ABBREVIATIONS IN THIS DOCUMENT

ACE	Area Control Error.
AGC	Automatic Generation Control.
ANSI	American National Standards Institute.
ATC	Available Transfer Capability.
BCP	Blackstart Capability Plan.
CBM	Capacity Benefit Margin.
CPS	Control Performance Standard.
DC	Direct Current.
DCS	Disturbance Control Standard.
DSM	Demand-Side Management.
ERO	Electric Reliability Organization.
GWh	Gigawatt hour.
IEEE	Institute of Electrical and Electronics Engineers.
IROL	Interconnection Reliability Operating Limits.
LSE	Load-serving Entity.
MVAR	Mega Volt Ampere Reactive.
MW	Mega Watt.
ROW	Right of Way.
SOL	System Operating Limit.
SPS	Special Protection System.
TIS	Transmission Issues Subcommittee.
TLR	Transmission Loading Relief.
TRM	Transmission Reliability Margin.
TTC	Total Transfer Capability.
UFLS	Underfrequency Load Shedding.
UVLS	Undervoltage Load Shedding.

[FR Doc. E7–5284 Filed 4–3–07; 8:45 am]

BILLING CODE 6717–01–P

Federal Register

Wednesday,
April 4, 2007

Part III

Postal Service

39 CFR Part 20
International Product and Price Changes; Final Rule

POSTAL SERVICE

39 CFR Part 20

International Product and Price Changes

AGENCY: Postal Service.

ACTION: Final rule.

SUMMARY: The Postal Service, after considering comments on its proposal to change international postal rates, fees, and mail classifications, is implementing the new published prices and mailing standards. The Postal Service may negotiate customized prices and mailing standards.

DATES: *Effective Date:* 12:01 a.m. on May 14, 2007.

FOR FURTHER INFORMATION CONTACT: Obataiye B. Akinwole, 202–268–7262; Tom Philson, 202–268–7355; or Janet Mitchell, 202–268–7522.

SUPPLEMENTARY INFORMATION: On December 20, 2006, the Postal Service published in the **Federal Register** (71 FR 76230) a notice of proposed international product and pricing initiatives. That notice proposed a major redesign of international products, including changes in published prices and supporting mail classifications. The redesign included two main features:

First, we proposed to more closely align international products with their domestic counterparts for ease of use and added value to our customers. We merged eight mailing options into four new alternatives by combining products with overlapping service standards and prices. We renamed the international products to mirror comparable domestic product names. Table 1 outlines our restructured products. The realignment merges all economy services including Publishers' Periodicals and Books and Sheet Music into categories with better service. Mailers who previously mailed their publication at Publishers' Periodicals rates may now apply meter postage to each copy, or for bulk mailings, use a permit imprint on the copies and submit a printed PS Form 3700, Postage Statement EM—International Mail.

TABLE 1

Previous products	New products	Features
Global Express Guaranteed® (documents) ..... Global Express Guaranteed® (non-document)	Global Express Guaranteed®	• 1–3 business day delivery. • Tracking available. • Money-back delivery guarantee[1]. • Insurance included.
Global Express Mail®	Express Mail® International	• 3–5 average business day delivery[2]. • Tracking available. • Service guarantee to Australia, China, Hong Kong, Republic of Korea (South Korea), and Japan. • Insurance included. • Flat-rate envelope.
Airmail Parcel Post ..... Economy Parcel Post ..... Global Priority Mail®	Priority Mail® International	• 6–10 average business day delivery[2]. • Tracking to major destinations. • Limited Insurance included.[3] • Flat-rate envelope and flat-rate box options available.
Airmail Letter Post ..... Economy Letter Post	First-Class Mail® International	• Available worldwide. • Registered Mail service available.

[1] Some restrictions apply. See retail associate for money-back guarantee details.
[2] Average delivery times may vary based upon origin and destination.
[3] Insurance is not available for the Priority Mail International flat-rate envelope.

Customers will be able to use the familiar expedited domestic packaging supplies for their expedited international shipments. We are also adding the popular flat-rate envelope option for Express Mail International, maintaining the flat-rate envelope option for Priority Mail International, and adding the flat-rate box option for Priority Mail International. In this final rule, we note the maximum weight limit for the Priority Mail International flat-rate box will be 20 pounds or the country specific maximum, whichever is less. In addition, we now offer more specific delivery time and tracking information to major destinations.

The second main feature of the redesign is an increase in published international prices by an average of 13 percent. This increase is necessary due to cost increases that occurred during a price freeze from January 2001 through January 2006.

We requested comments on our proposed rule and received 37 comments before the January 19, 2007, closing date. In response to requests from book mailers, we extended the comment period to February 2 and received an additional 28 comments. We included 5 comments received past the February 2 date. In total, we received comments from one industry association, two mailing agents, three equipment service providers, fifty-five mailers, and four individuals. We summarize the three major categories of comments and respond in items 1 through 3, below.

1. Price Changes for Bulk Letter Services

We received 36 comments questioning the magnitude of the published pricing change for International Priority Airmail (IPA) and International Surface Airlift (ISAL). Customized prices can be negotiated for IPA and ISAL. Over the past five years, the cost coverage for these services has deteriorated.

All international and domestic services must cover their attributable costs and make a reasonable contribution to our institutional costs. The published price increases will allow us to meet that requirement. The average published price increases for IPA and ISAL are 14.1 percent and 13.1 percent, respectively. Depending on the destination country group, price increases may be more or less than the average.

After carefully reviewing and considering all comments, we decided not to modify the published price increases in our proposal because these

price increases are justified and necessary.

2. Restructuring Services

Twenty-three commenters objected to our proposal to eliminate surface-transported economy services. We have experienced continuing volume decline for these economy services. Economy services that use surface transportation account for only 2.7 percent of total international volume. The declining volumes indicate that demand for faster services has increased at the expense of services that use surface transportation to foreign destinations. As a result, efficient international surface delivery networks have diminished and costs have dramatically increased. In addition, the lack of efficient surface delivery networks has led to lengthy and inconsistent delivery times for economy service to many destinations.

We understand the concerns of mailers who use economy services, and customized agreements may be developed that involve different prices and standards from those presented in this rule.

3. Miscellaneous

Three respondents commented on our online discounts. Customers who purchase postage using Click-N-Ship at *http://www.usps.com*, or through an authorized online provider, will receive discounts of 10 percent on Global Express Guaranteed, 8 percent on Express Mail International, and 5 percent on Priority Mail International. These commenters asked us to extend the discounts to postage meter customers. Postage meters cannot meet the specific requirements for the discounts; therefore, we cannot offer these discounts to postage meter customers.

One commenter expressed concern about eliminating Recorded Delivery, Aerogrammes, and the small flat-rate envelope for Global Priority Mail. We are eliminating Recorded Delivery and Aerogrammes because of a lack of customer demand, and the availability of alternatives. Over the past five years volumes declined for these services and costs increased. In FY 2005, Aerogramme revenue was under $200,000, with fewer than 250,000 Aerogrammes sent. Recorded Delivery revenue was approximately $3,000 on slightly over 1,000 transactions. As an alternative, Aerogramme mailers can use either postcards or First-Class Mail International services. Previously purchased Aerogrammes will remain mailable at the applicable First-Class Mail International rate. Recorded Delivery mailers can use Registered Mail.

Regarding the small flat-rate envelope for Global Priority Mail, as part of our product simplification and to more closely align domestic and international products, we will offer only one flat-rate envelope for Priority Mail International, using the same packaging as domestic Priority Mail. All items previously mailable in the Global Priority flat-rate envelope can be mailed in the new Priority Mail International flat-rate envelope. The maximum weight limit will remain 4 pounds.

We received one comment questioning our decision to charge the same rate for postcards as we do for letters. In simplifying the pricing schedule, we made the decision to charge the same price for the base First-Class Mail International letter as we do for postcards. Postcards are a small percentage of the total letter-post volume, and we believe that it would be more convenient for customers to use the same postage and stamps for both of these services. First-Class Mail International letters and cards are processed, transported, and delivered in the same operational stream and have the same cost structure. We limited the price increase for the base one-ounce First-Class Mail International letter to under the system-wide average in part because of the rate increase to existing postcard users. After carefully reviewing and considering this comment, we have decided not to modify the price increases we proposed for postcards.

One commenter questioned the proposed dimensional weight criteria for GXG. Dimensional weight determines the appropriate rate of postage based on the size of a shipment in relation to its weight. Our dimensional weight criteria are consistent with those used by the shipping industry. As the commenter noted, our rounding method needed clarification. We changed the rounding method to mirror that of the domestic rounding method used for Priority Mail.

We received two comments from mailers concerning the overall published price increase for international products and the effect this increase may have on their businesses. The average increase in international prices is 13 percent and is necessary because of cost increases that occurred during a price freeze from January 2001 through January 2006. Also, the GXG rates in the December 20, 2006, proposal were misaligned and have been corrected in this final rule.

When designing our published international prices, we are cognizant of the intense competitive environment in which we and our customers compete. For that reason, we moderated our increases in our pricing design. After carefully reviewing and considering these comments, we decided not to modify the price increases that we proposed because the price increases are justified and are necessary to cover our costs.

One commenter asked us to provide a list of country-specific extra services and weight options. We included the weight options for Express Mail International and Priority Mail International in this final rule.

We provide the updated IMM standards for our published prices, and how they are applied for each type of mail, below.

After reviewing and considering the comments, we adopt the following changes to the *Mailing Standards of the United States Postal Service, International Mail Manual (IMM)*, incorporated by reference in the Code of Federal Regulations. See 39 CFR 20.1.

List of Subjects in 39 CFR Part 20

Foreign relations, International postal services.

PART 20—[AMENDED]

■ 1. The authority citation for 39 CFR part 20 continues to read as follows:

Authority: 5 U.S.C. 552(a); 39 U.S.C. 401, 404, 407, 408.

■ 2. Revise the Mailing Standards of the United States Postal Service, International Mail Manual (IMM) to incorporate the following postage rates, fees, and rate groups.

International Rates and Fees

COUNTRY LISTING

Country	GXG [1] rate group	EMS [2] rate group	EMS max. weight limit (lb.)	PMI [3] rate group	PMI max. weight limit (lb.)	PMI insurance indemnity limit ($)	FCMI [4] rate group	IPA & ISAL [5] rate group
A								
Afghanistan	6			5	66		5	8

COUNTRY LISTING—Continued

Country	GXG [1] rate group	EMS [2] rate group	EMS max. weight limit (lb.)	PMI [3] rate group	PMI max. weight limit (lb.)	PMI insurance indemnity limit ($)	FCMI [4] rate group	IPA & ISAL [5] rate group
Albania	4	4	22	4	44	.....	5	5
Algeria	4	8	44	8	44	.....	5	8
Andorra	5	5	66	5	66	5000	3	3
Angola	4	7	44	7	44	.....	5	8
Anguilla	7	9	44	9	22	415	5	6
Antigua & Barbuda	7	.....	.....	9	22	60	5	6
Argentina	8	9	44	9	44	5000	5	6
Armenia	4	4	44	4	44	875	5	8
Aruba	7	9	44	9	44	830	5	6
Ascension	.....	.....	.....	.....	.....	.....	5	5
Australia	6	3	44	3	66	3644	4	9
Austria	5	5	66	5	66	5000	3	3
Azerbaijan	4	4	44	4	70	2915	5	8
B								
Bahamas	7	9	44	9	22	[6] 1458/560	5	6
Bahrain	6	8	44	8	44	.....	5	8
Bangladesh	6	6	44	6	44	5000	5	8
Barbados	7	9	44	9	44	238	5	6
Belarus	4	4	44	4	66	1312	5	5
Belgium	3	5	66	5	66	650	3	3
Belize	8	9	44	9	44	1600	5	6
Benin	4	7	44	7	66	.....	5	8
Bermuda	7	9	44	9	44	440	5	6
Bhutan	6	6	44	6	66	22	5	8
Bolivia	8	9	44	9	70	.....	5	6
Bosnia-Herzegovina	4	4	66	4	44	5000	5	5
Botswana	4	7	44	7	66	73	5	8
Brazil	8	9	66	9	66	2915	5	6
British Virgin Islands	7	.....	.....	9	44	500	5	6
Brunei Darussalam	4	6	44	6	44	.....	5	7
Bulgaria	4	4	44	4	70	1115	5	5
Burkina Faso	4	7	66	7	66	969	5	8
Burma (Myanmar)	.....	.....	.....	6	22	.....	5	8
Burundi	4	7	22	7	66	5000	5	8
C								
Cambodia	8	6	44	6	66	.....	5	7
Cameroon	4	7	44	7	66	5000	5	8
Canada	1	1	66	1	66	675	1	1
Cape Verde	4	7	44	7	44	.....	5	8
Cayman Islands	7	9	44	9	44	.....	5	6
Central African Republic	4	7	44	7	66	.....	5	8
Chad	4	7	44	7	44	185	5	8
Chile	8	9	33	9	44	.....	5	6
China	6	3	66	3	66	1222	5	7
Colombia	8	9	44	9	66	999	5	6
Comoros	.....	.....	.....	7	44	690	5	8
Congo, Democratic Republic of the	4	7	44	7	66	.....	5	8
Congo, Republic of the	4	7	44	7	44	1685	5	8
Costa Rica	8	9	44	9	66	.....	5	6
Cote d'Ivoire (Ivory Coast)	4	7	66	7	66	5000	5	8
Croatia	4	4	66	4	66	5000	5	5
Cuba	.....	.....	.....	.....	.....	.....	5	6
Cyprus	6	4	70	4	70	5000	5	8
Czech Republic	4	4	66	4	66	5000	5	5
D								
Denmark	5	5	66	5	66	650	3	3
Djibouti	4	7	44	7	44	880	5	8
Dominica	7	9	44	9	44	.....	5	6
Dominican Republic	7	9	44	9	44	.....	5	6
E								
Ecuador	8	9	66	9	66	.....	5	6
Egypt	6	8	44	8	66	1685	5	8
El Salvador	8	9	33	9	44	.....	5	6
Equatorial Guinea	4	7	44	7	22	.....	5	8
Eritrea	4	7	66	7	44	.....	5	8
Estonia	4	4	66	4	70	2187	5	5
Ethiopia	4	8	44	8	66	.....	5	8

COUNTRY LISTING—Continued

Country	GXG [1] rate group	EMS [2] rate group	EMS max. weight limit (lb.)	PMI [3] rate group	PMI max. weight limit (lb.)	PMI insurance indemnity limit ($)	FCMI [4] rate group	IPA & ISAL [5] rate group
F								
Falkland Islands	.....	.....	.....	.....	.....	.....	5	6
Faroe Islands	5	5	44	5	70	5000	3	5
Fiji	8	6	44	6	44	.....	5	7
Finland	5	5	66	5	70	650	3	3
France	3	5	66	5	66	650	3	3
French Guiana	8	9	66	9	66	5000	5	6
French Polynesia	4	6	44	6	66	4519	5	7
G								
Gabon	4	7	44	7	44	523	5	8
Gambia	4	.....	.....	7	66	.....	5	8
Georgia, Republic of	4	4	66	4	44	1458	5	8
Germany	3	5	66	5	70	500	3	3
Ghana	4	7	44	7	66	.....	5	8
Gibraltar	4	.....	.....	5	44	.....	3	3
Great Britain & Northern Ireland	3	5	66	5	66	650	3	3
Greece	5	5	66	5	44	650	3	3
Greenland	5	.....	.....	4	66	5000	3	3
Grenada	7	9	22	9	44	350	5	6
Guadeloupe	7	9	66	9	66	5000	5	6
Guatemala	8	9	44	9	44	.....	5	6
Guinea	4	7	44	7	66	948	5	8
Guinea-Bissau	4	7	44	7	66	2915	5	8
Guyana	8	9	44	9	44	10	5	6
H								
Haiti	7	9	70	9	55	.....	5	6
Honduras	8	9	44	9	44	.....	5	6
Hong Kong	3	3	66	3	66	5000	5	7
Hungary	4	4	44	4	44	5000	5	5
I								
Iceland	5	5	44	5	70	650	3	3
India	6	6	44	6	44	2189	5	8
Indonesia	6	6	22	6	44	.....	5	7
Iran	.....	.....	.....	8	44	.....	5	8
Iraq	6	8	44	8	66	.....	5	8
Ireland (Eire)	3	5	66	5	66	650	3	3
Israel	6	8	33	8	44	.....	3	3
Italy	3	5	66	5	66	650	3	3
J								
Jamaica	7	9	44	9	22	.....	5	6
Japan	3	3	66	3	66	5000	4	4
Jordan	6	8	66	8	66	.....	5	8
K								
Kazakhstan	4	6	44	6	44	5000	5	8
Kenya	4	7	44	7	70	131	5	8
Kiribati	.....	.....	.....	6	44	.....	5	7
Korea, Democratic People's Republic of (North)	.....	.....	.....	.....	.....	.....	5	7
Korea, Republic of (South)	6	3	66	3	44	5000	5	7
Kuwait	6	8	44	8	66	2000	5	8
Kyrgyzstan	4	6	44	6	44	5000	5	5
L								
Laos	8	6	44	6	44	.....	5	7
Latvia	4	4	44	4	70	1458	5	5
Lebanon	6	.....	.....	8	66	65	5	8
Lesotho	4	7	44	7	44	440	5	8
Liberia	4	7	44	7	44	440	5	8
Libya	.....	.....	.....	8	44	.....	5	8
Liechtenstein	5	5	66	5	66	5000	3	3
Lithuania	4	4	44	4	70	5000	5	5
Luxembourg	3	5	66	5	66	650	3	3
M								
Macao	3	6	66	6	70	4227	5	5
Macedonia, Republic of	4	4	66	4	70	2380	5	5
Madagascar	4	7	66	7	44	199	5	8
Malawi	4	7	44	7	66	.....	5	8
Malaysia	6	6	66	6	66	1429	5	7

COUNTRY LISTING—Continued

Country	GXG [1] rate group	EMS [2] rate group	EMS max. weight limit (lb.)	PMI [3] rate group	PMI max. weight limit (lb.)	PMI insurance indemnity limit ($)	FCMI [4] rate group	IPA & ISAL [5] rate group
Maldives	6	6	44	6	66	.....	5	8
Mali	4	7	44	7	66	.....	5	8
Malta	5	5	66	5	66	.....	5	8
Marshall Islands	4	10	70	10	70	.....	6	3
Martinique	7	9	66	9	66	5000	5	6
Mauritania	4	7	44	7	44	635	5	8
Mauritius	4	7	44	7	44	165	5	8
Mexico	2	2	66	2	44	.....	2	2
Micronesia	4	10	70	10	70	.....	6	3
Moldova	4	4	44	4	70	2915	5	8
Mongolia	4	6	44	6	66	.....	5	7
Montserrat	7	.....	.....	9	44	2200	5	6
Morocco	4	8	66	8	66	5000	5	8
Mozambique	4	7	44	7	66	.....	5	8
N								
Namibia	4	7	44	7	44	4405	5	8
Nauru	.....	6	44	6	44	220	5	7
Nepal	6	6	44	6	44	.....	5	7
Netherlands	3	5	66	5	44	650	3	3
Netherlands Antilles	7	9	44	9	44	5000	5	6
New Caledonia	8	6	44	6	66	1775	5	7
New Zealand	6	6	44	6	66	1025	4	4
Nicaragua	8	9	44	9	66	.....	5	6
Niger	4	7	70	7	70	.....	5	8
Nigeria	4	7	44	7	66	.....	5	8
Norway	5	5	66	5	66	650	3	3
O								
Oman	6	8	44	8	44	575	5	8
P								
Pakistan	6	6	22	6	70	867	5	8
Panama	8	9	66	9	70	.....	5	6
Papua New Guinea	8	6	44	6	44	445	5	7
Paraguay	8	9	44	9	66	.....	5	6
Peru	8	9	66	9	70	.....	5	6
Philippines	6	6	44	6	44	.....	5	7
Pitcairn Island	.....	.....	.....	6	22	.....	5	7
Poland	4	4	44	4	44	5000	5	5
Portugal	5	5	66	5	66	650	3	3
Q								
Qatar	6	8	44	8	70	.....	5	8
R								
Reunion	4	.....	.....	9	66	5000	5	8
Romania	4	4	22	4	70	5000	5	5
Russia	4	4	44	4	44	5000	5	5
Rwanda	4	7	44	7	66	.....	5	8
S								
St. Christopher (St. Kitts) & Nevis	7	9	44	9	44	242	5	6
Saint Helena	.....	.....	.....	7	44	170	5	8
Saint Lucia	7	9	44	9	44	.....	5	6
Saint Pierre & Miquelon	.....	.....	.....	4	66	5000	5	6
Saint Vincent & Grenadines	7	9	44	9	22	130	5	6
San Marino	3	5	66	5	66	5000	3	3
Sao Tome & Principe	.....	.....	.....	7	44	440	5	5
Saudi Arabia	4	8	66	8	66	.....	5	8
Senegal	4	7	44	7	66	936	5	8
Serbia-Montenegro (Yugoslavia)	4	5	70	5	70	5000	5	5
Seychelles	4	7	44	7	70	.....	5	8
Sierra Leone	4	7	44	7	66	.....	5	8
Singapore	3	6	66	6	66	5000	5	7
Slovak Republic (Slovakia)	4	5	66	5	66	650	5	5
Slovenia	4	5	66	5	66	650	5	5
Solomon Islands	.....	6	44	6	44	.....	5	7
Somalia	.....	.....	.....	.....	.....	.....	.....	8
South Africa	4	7	44	7	66	.....	5	8
Spain	5	5	66	5	44	650	3	3
Sri Lanka	6	6	44	6	66	35	5	8

COUNTRY LISTING—Continued

Country	GXG [1] rate group	EMS [2] rate group	EMS max. weight limit (lb.)	PMI [3] rate group	PMI max. weight limit (lb.)	PMI insurance indemnity limit ($)	FCMI [4] rate group	IPA & ISAL [5] rate group
Sudan	.....	7	44	7	44	.....	5	8
Suriname	8	.....	.....	9	44	535	5	6
Swaziland	4	7	44	7	44	560	5	8
Sweden	5	5	66	5	66	650	3	3
Switzerland	5	5	66	5	66	650	3	3
Syrian Arab Republic (Syria)	6	8	44	8	70	.....	5	8
T								
Taiwan	3	6	33	6	44	1350	5	7
Tajikistan	.....	6	44	6	66	5000	5	8
Tanzania	4	7	22	7	66	248	5	8
Thailand	6	6	44	6	66	1458	5	7
Togo	4	7	44	7	70	.....	5	8
Tonga	4	.....	.....	6	44	515	5	7
Trinidad & Tobago	7	9	44	9	44	.....	5	6
Tristan da Cunha	.....	.....	.....	7	22	.....	5	8
Tunisia	4	8	44	8	66	3834	5	8
Turkey	6	4	44	4	66	952	5	5
Turkmenistan	4	6	44	6	44	729	5	5
Turks & Caicos Islands	7	.....	.....	9	44	.....	5	6
Tuvalu	.....	.....	.....	6	55	675	5	7
U								
Uganda	4	7	22	7	66	.....	5	8
Ukraine	4	4	44	4	66	5000	5	8
United Arab Emirates	6	8	44	8	70	5000	5	8
Uruguay	8	9	44	9	66	.....	5	6
Uzbekistan	4	.....	.....	6	70	5000	5	8
V								
Vanuatu	8	6	22	6	44	.....	5	7
Vatican City	3	5	66	5	44	2380	3	3
Venezuela	8	9	44	9	66	.....	5	6
Vietnam	6	6	44	6	70	.....	5	7
W								
Wallis & Futuna Islands	4	.....	.....	6	66	1615	5	7
Western Samoa	4	6	44	6	44	295	5	7
Y								
Yemen	6	8	66	8	66	820	5	8
Z								
Zambia	4	7	44	7	66	.....	5	8
Zimbabwe	4	7	44	7	44	.....	5	8

[1] Global Express Guaranteed.
[2] Express Mail International.
[3] Priority Mail International.
[4] First-Class Mail International.
[5] ISAL service not available to all countries. See IMM Country Listings for availability.
[6] Bahamas: PMI Indemnity limit is $1458 to Nassau and Freeport and $560 to all other locations.

GLOBAL EXPRESS GUARANTEED

Weight not over (pounds)	Rate group 1	Rate group 2	Rate group 3	Rate group 4	Rate group 5	Rate group 6	Rate group 7	Rate group 8
0.5	$28.50	$28.75	$37.00	75.00	$38.00	$38.00	$37.00	$52.00
1	$41.00	$42.50	$49.00	$93.00	$58.00	$55.00	$47.00	$65.00
2	$44.50	$47.50	$56.00	$107.75	$65.75	$63.45	$54.20	$80.90
3	$48.00	$52.50	$63.00	$122.50	$73.50	$71.90	$61.40	$96.80
4	$51.50	$57.50	$70.00	$137.25	$81.25	$80.35	$68.60	$112.70
5	$55.00	$62.50	$77.00	$152.00	$89.00	$88.80	$75.80	$128.60
6	$58.50	$67.50	$84.00	$166.75	$96.75	$97.25	$83.00	$144.50
7	$62.00	$72.50	$91.00	$181.50	$104.50	$105.70	$90.20	$160.40
8	$65.50	$77.50	$98.00	$196.25	$112.25	$114.15	$97.40	$176.30
9	$69.00	$82.50	$105.00	$211.00	$120.00	$122.60	$104.60	$192.20
10	$72.50	$87.50	$112.00	$225.75	$127.75	$131.05	$111.80	$208.10
11	$75.35	$90.65	$116.30	$237.00	$132.65	$137.45	$116.05	$218.10
12	$78.20	$93.80	$120.60	$248.25	$137.55	$143.85	$120.30	$228.10
13	$81.05	$96.95	$124.90	$259.50	$142.45	$150.25	$124.55	$238.10

GLOBAL EXPRESS GUARANTEED—Continued

Weight not over (pounds)	Rate group 1	Rate group 2	Rate group 3	Rate group 4	Rate group 5	Rate group 6	Rate group 7	Rate group 8
14	$83.90	$100.10	$129.20	$270.75	$147.35	$156.65	$128.80	$248.10
15	$86.75	$103.25	$133.50	$282.00	$152.25	$163.05	$133.05	$258.10
16	$89.60	$106.40	$137.80	$293.25	$157.15	$169.45	$137.30	$268.10
17	$92.45	$109.55	$142.10	$304.50	$162.05	$175.85	$141.55	$278.10
18	$95.30	$112.70	$146.40	$315.75	$166.95	$182.25	$145.80	$288.10
19	$98.15	$115.85	$150.70	$327.00	$171.85	$188.65	$150.05	$298.10
20	$101.00	$119.00	$155.00	$338.25	$176.75	$195.05	$154.30	$308.10
21	$103.85	$122.15	$159.30	$349.50	$181.65	$201.45	$158.55	$318.10
22	$106.70	$125.30	$163.60	$360.75	$186.55	$207.85	$162.80	$328.10
23	$109.55	$128.45	$167.90	$372.00	$191.45	$214.25	$167.05	$338.10
24	$112.40	$131.60	$172.20	$383.25	$196.35	$220.65	$171.30	$348.10
25	$115.25	$134.75	$176.50	$394.50	$201.25	$227.05	$175.55	$358.10
26	$118.10	$137.90	$180.80	$405.75	$206.15	$233.45	$179.80	$368.10
27	$120.95	$141.05	$185.10	$417.00	$211.05	$239.85	$184.05	$378.10
28	$123.80	$144.20	$189.40	$428.25	$215.95	$246.25	$188.30	$388.10
29	$126.65	$147.35	$193.70	$439.50	$220.85	$252.65	$192.55	$398.10
30	$129.50	$150.50	$198.00	$450.75	$225.75	$259.05	$196.80	$408.10
31	$132.35	$153.65	$202.30	$462.00	$230.65	$265.45	$201.05	$418.10
32	$135.20	$156.80	$206.60	$473.25	$235.55	$271.85	$205.30	$428.10
33	$138.05	$159.95	$210.90	$484.50	$240.45	$278.25	$209.55	$438.10
34	$140.90	$163.10	$215.20	$495.75	$245.35	$284.65	$213.80	$448.10
35	$143.75	$166.25	$219.50	$507.00	$250.25	$291.05	$218.05	$458.10
36	$146.60	$169.40	$223.80	$518.25	$255.15	$297.45	$222.30	$468.10
37	$149.45	$172.55	$228.10	$529.50	$260.05	$303.85	$226.55	$478.10
38	$152.30	$175.70	$232.40	$540.75	$264.95	$310.25	$230.80	$488.10
39	$155.15	$178.85	$236.70	$552.00	$269.85	$316.65	$235.05	$498.10
40	$158.00	$182.00	$241.00	$563.25	$274.75	$323.05	$239.30	$508.10
41	$160.10	$184.10	$245.30	$571.50	$279.55	$329.20	$243.45	$516.60
42	$162.20	$186.20	$249.60	$579.75	$284.35	$335.35	$247.60	$525.10
43	$164.30	$188.30	$253.90	$588.00	$289.15	$341.50	$251.75	$533.60
44	$166.40	$190.40	$258.20	$596.25	$293.95	$347.65	$255.90	$542.10
45	$168.50	$192.50	$262.50	$604.50	$298.75	$353.80	$260.05	$550.60
46	$170.60	$194.60	$266.80	$612.75	$303.55	$359.95	$264.20	$559.10
47	$172.70	$196.70	$271.10	$621.00	$308.35	$366.10	$268.35	$567.60
48	$174.80	$198.80	$275.40	$629.25	$313.15	$372.25	$272.50	$576.10
49	$176.90	$200.90	$279.70	$637.50	$317.95	$378.40	$276.65	$584.60
50	$179.00	$203.00	$284.00	$645.75	$322.75	$384.55	$280.80	$593.10
51	$181.10	$205.10	$288.30	$654.00	$327.55	$390.70	$284.95	$601.60
52	$183.20	$207.20	$292.60	$662.25	$332.35	$396.85	$289.10	$610.10
53	$185.30	$209.30	$296.90	$670.50	$337.15	$403.00	$293.25	$618.60
54	$187.40	$211.40	$301.20	$678.75	$341.95	$409.15	$297.40	$627.10
55	$189.50	$213.50	$305.50	$687.00	$346.75	$415.30	$301.55	$635.60
56	$191.60	$215.60	$309.80	$695.25	$351.55	$421.45	$305.70	$644.10
57	$193.70	$217.70	$314.10	$703.50	$356.35	$427.60	$309.85	$652.60
58	$195.80	$219.80	$318.40	$711.75	$361.15	$433.75	$314.00	$661.10
59	$197.90	$221.90	$322.70	$720.00	$365.95	$439.90	$318.15	$669.60
60	$200.00	$224.00	$327.00	$728.25	$370.75	$446.05	$322.30	$678.10
61	$202.10	$226.10	$331.30	$736.50	$375.55	$452.20	$326.45	$686.60
62	$204.20	$228.20	$335.60	$744.75	$380.35	$458.35	$330.60	$695.10
63	$206.30	$230.30	$339.90	$753.00	$385.15	$464.50	$334.75	$703.60
64	$208.40	$232.40	$344.20	$761.25	$389.95	$470.65	$338.90	$712.10
65	$210.50	$234.50	$348.50	$769.50	$394.75	$476.80	$343.05	$720.60
66	$212.60	$236.60	$352.80	$777.75	$399.55	$482.95	$347.20	$729.10
67	$214.70	$238.70	$357.10	$786.00	$404.35	$489.10	$351.35	$737.60
68	$216.80	$240.80	$361.40	$794.25	$409.15	$495.25	$355.50	$746.10
69	$218.90	$242.90	$365.70	$802.50	$413.95	$501.40	$359.65	$754.60
70	$221.00	$245.00	$370.00	$810.75	$418.75	$507.55	$363.80	$763.10

EXPRESS MAIL INTERNATIONAL

Weight not over (pounds)	Rate group 1	Rate group 2	Rate group 3	Rate group 4	Rate group 5	Rate group 6	Rate group 7	Rate group 8	Rate group 9	Rate group 10
0.5	$22.00	$22.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$19.75
1	$23.25	$25.50	$28.00	$27.50	$30.50	$27.00	$32.00	$32.00	$30.00	$22.50
2	$25.00	$30.00	$32.00	$30.50	$34.75	$31.00	$37.00	$36.85	$34.75	$25.25
3	$26.75	$34.50	$36.00	$33.50	$39.00	$35.00	$42.00	$41.70	$39.50	$28.75
4	$28.50	$39.00	$40.00	$36.50	$43.25	$39.00	$47.00	$46.55	$44.25	$32.25
5	$30.25	$43.50	$44.00	$39.50	$47.50	$43.00	$52.00	$51.40	$49.00	$35.50
6	$32.00	$46.10	$47.85	$43.00	$51.25	$47.00	$57.00	$56.40	$53.75	$39.00
7	$33.75	$48.70	$51.70	$46.50	$55.00	$51.00	$62.00	$61.40	$58.50	$42.50
8	$35.50	$51.30	$55.55	$50.00	$58.75	$55.00	$67.00	$66.40	$63.25	$46.00
9	$37.25	$53.90	$59.40	$53.50	$62.50	$59.00	$72.00	$71.40	$68.00	$49.50
10	$39.00	$56.50	$63.25	$57.00	$66.25	$63.00	$77.00	$76.40	$72.75	$52.25
11	$41.50	$59.10	$67.10	$61.10	$70.00	$68.25	$82.35	$81.40	$78.00	$55.75
12	$44.00	$61.70	$70.95	$65.20	$73.75	$73.50	$87.70	$86.40	$83.25	$59.25
13	$46.50	$64.30	$74.80	$69.30	$77.50	$78.75	$93.05	$91.40	$88.50	$62.50
14	$49.00	$66.90	$78.65	$73.40	$81.25	$84.00	$98.40	$96.40	$93.75	$66.00
15	$51.50	$69.50	$82.50	$77.50	$85.00	$89.25	$103.75	$101.40	$99.00	$69.25
16	$54.00	$72.10	$86.35	$81.60	$88.75	$94.50	$109.10	$106.40	$104.25	$72.75
17	$56.50	$74.70	$90.20	$85.70	$92.50	$99.75	$114.45	$111.40	$109.50	$76.00
18	$59.00	$77.30	$94.05	$89.80	$96.25	$105.00	$119.80	$116.40	$114.75	$79.50
19	$61.50	$79.90	$97.90	$93.90	$100.00	$110.25	$125.15	$121.40	$120.00	$82.75
20	$64.00	$82.50	$101.75	$98.00	$103.75	$115.50	$130.50	$126.40	$125.25	$86.25
21	$66.50	$85.10	$105.60	$102.10	$107.50	$120.75	$135.85	$131.40	$130.50	$89.75
22	$69.00	$87.70	$109.45	$106.20	$111.25	$126.00	$141.20	$136.40	$135.75	$93.00
23	$71.50	$90.30	$113.30	$110.30	$115.00	$131.25	$146.55	$141.40	$141.00	$96.50
24	$74.00	$92.90	$117.15	$114.40	$118.75	$136.50	$151.90	$146.40	$146.25	$99.75
25	$76.50	$95.50	$121.00	$118.50	$122.50	$141.75	$157.25	$151.40	$151.50	$103.25
26	$79.00	$98.10	$124.85	$122.60	$126.25	$147.00	$162.60	$156.40	$156.75	$106.50
27	$81.50	$100.70	$128.70	$126.70	$130.00	$152.25	$167.95	$161.40	$162.00	$110.00
28	$84.00	$103.30	$132.55	$130.80	$133.75	$157.50	$173.30	$166.40	$167.25	$113.25
29	$86.50	$105.90	$136.40	$134.90	$137.50	$162.75	$178.65	$171.40	$172.50	$116.75
30	$89.00	$108.50	$140.25	$139.00	$141.25	$168.00	$184.00	$176.40	$177.75	$120.25
31	$91.50	$111.10	$144.10	$143.10	$145.00	$173.25	$189.35	$181.40	$183.00	$123.50
32	$94.00	$113.70	$147.95	$147.20	$148.75	$178.50	$194.70	$186.40	$188.25	$127.00
33	$96.50	$116.30	$151.80	$151.30	$152.50	$183.75	$200.05	$191.40	$193.50	$130.25
34	$99.00	$118.90	$155.65	$155.40	$156.25	$189.00	$205.40	$196.40	$198.75	$133.75
35	$101.50	$121.50	$159.50	$159.50	$160.00	$194.25	$210.75	$201.40	$204.00	$137.00
36	$104.00	$124.10	$163.35	$163.60	$163.75	$199.50	$216.10	$206.40	$209.25	$140.50
37	$106.50	$126.70	$167.20	$167.70	$167.50	$204.75	$221.45	$211.40	$214.50	$144.00
38	$109.00	$129.30	$171.05	$171.80	$171.25	$210.00	$226.80	$216.40	$219.75	$147.25
39	$111.50	$131.90	$174.90	$175.90	$175.00	$215.25	$232.15	$221.40	$225.00	$150.75
40	$114.00	$134.50	$178.75	$180.00	$178.75	$220.50	$237.50	$226.40	$230.25	$154.00
41	$116.50	$137.10	$182.60	$184.10	$182.50	$225.75	$242.85	$231.40	$235.50	$157.50
42	$119.00	$139.70	$186.45	$188.20	$186.25	$231.00	$248.20	$236.40	$240.75	$160.75
43	$121.50	$142.30	$190.30	$192.30	$190.00	$236.25	$253.55	$241.40	$246.00	$164.25
44	$124.00	$144.90	$194.15	$196.40	$193.75	$241.50	$258.90	$246.40	$251.25	$167.50
45	$126.50	$147.50	$198.00	$200.50	$197.50	$246.75	$264.25	$251.40	$256.50	$171.00
46	$129.00	$150.10	$201.85	$204.60	$201.25	$252.00	$269.60	$256.40	$261.75	$174.50
47	$131.50	$152.70	$205.70	$208.70	$205.00	$257.25	$274.95	$261.40	$267.00	$177.75
48	$134.00	$155.30	$209.55	$212.80	$208.75	$262.50	$280.30	$266.40	$272.25	$181.25
49	$136.50	$157.90	$213.40	$216.90	$212.50	$267.75	$285.65	$271.40	$277.50	$184.50
50	$139.00	$160.50	$217.25	$221.00	$216.25	$273.00	$291.00	$276.40	$282.75	$188.00
51	$141.50	$163.10	$221.10	$225.10	$220.00	$278.25	$296.35	$281.40	$288.00	$191.25
52	$144.00	$165.70	$224.95	$229.20	$223.75	$283.50	$301.70	$286.40	$293.25	$194.75
53	$146.50	$168.30	$228.80	$233.30	$227.50	$288.75	$307.05	$291.40	$298.50	$198.00
54	$149.00	$170.90	$232.65	$237.40	$231.25	$294.00	$312.40	$296.40	$303.75	$201.50
55	$151.50	$173.50	$236.50	$241.50	$235.00	$299.25	$317.75	$301.40	$309.00	$205.00
56	$154.00	$176.10	$240.35	$245.60	$238.75	$304.50	$323.10	$306.40	$314.25	$208.25
57	$156.50	$178.70	$244.20	$249.70	$242.50	$309.75	$328.45	$311.40	$319.50	$211.75
58	$159.00	$181.30	$248.05	$253.80	$246.25	$315.00	$333.80	$316.40	$324.75	$215.00
59	$161.50	$183.90	$251.90	$257.90	$250.00	$320.25	$339.15	$321.40	$330.00	$218.50

EXPRESS MAIL INTERNATIONAL—Continued

Weight not over (pounds)	Rate group 1	Rate group 2	Rate group 3	Rate group 4	Rate group 5	Rate group 6	Rate group 7	Rate group 8	Rate group 9	Rate group 10
60	$164.00	$186.50	$255.75	$262.00	$253.75	$325.50	$344.50	$326.40	$335.25	$221.75
61	$166.50	$189.10	$259.60	$266.10	$257.50	$330.75	$349.85	$331.40	$340.50	$225.25
62	$169.00	$191.70	$263.45	$270.20	$261.25	$336.00	$355.20	$336.40	$345.75	$228.75
63	$171.50	$194.30	$267.30	$274.30	$265.00	$341.25	$360.55	$341.40	$351.00	$232.00
64	$174.00	$196.90	$271.15	$278.40	$268.75	$346.50	$365.90	$346.40	$356.25	$235.50
65	$176.50	$199.50	$275.00	$282.50	$272.50	$351.75	$371.25	$351.40	$361.50	$238.75
66	$179.00	$202.10	$278.85	$286.60	$276.25	$357.00	$376.60	$356.40	$366.75	$242.25
67	.....	.....	.....	$290.70	.....	$362.25	$381.95	$361.40	$372.00	$245.50
68	.....	.....	.....	$294.80	.....	$367.50	$387.30	$366.40	$377.25	$249.00
69	.....	.....	.....	$298.90	.....	$372.75	$392.65	$371.40	$382.50	$252.25
70	.....	.....	.....	$303.00	.....	$378.00	$398.00	$376.40	$387.75	$255.75

EXPRESS MAIL INTERNATIONAL—FLAT-RATE ENVELOPE

Destination country	Envelope
CANADA & MEXICO	$22.00
ALL OTHER COUNTRIES	$25.00

PRIORITY MAIL INTERNATIONAL [1]

Weight not over (pounds)	Rate group 1	Rate group 2	Rate group 3	Rate group 4	Rate group 5	Rate group 6	Rate group 7	Rate group 8	Rate group 9	Rate group 10
1	$16.00	$16.50	$21.00	$18.50	$20.00	$18.50	$21.00	$20.00	$18.00	$10.20
2	$17.30	$19.75	$25.25	$21.75	$24.00	$22.70	$25.50	$24.00	$21.60	$12.10
3	$18.60	$23.00	$29.50	$25.00	$28.00	$26.90	$30.00	$28.00	$25.20	$14.30
4	$19.90	$26.25	$33.75	$28.25	$32.00	$31.10	$34.50	$32.00	$28.80	$16.60
5	$21.20	$29.50	$38.00	$31.50	$36.00	$35.30	$39.00	$36.00	$32.40	$18.70
6	$22.50	$31.80	$41.60	$34.65	$39.30	$39.90	$43.50	$40.35	$35.90	$20.90
7	$23.80	$34.10	$45.20	$37.80	$42.60	$44.50	$48.00	$44.70	$39.40	$23.10
8	$25.10	$36.40	$48.80	$40.95	$45.90	$49.10	$52.50	$49.05	$42.90	$25.40
9	$26.40	$38.70	$52.40	$44.10	$49.20	$53.70	$57.00	$53.40	$46.40	$27.70
10	$27.70	$41.00	$56.00	$47.25	$52.50	$58.30	$61.50	$57.75	$49.90	$29.90
11	$29.10	$43.30	$59.60	$50.85	$55.80	$62.90	$65.85	$62.10	$53.40	$32.20
12	$30.50	$45.60	$63.20	$54.45	$59.10	$67.50	$70.20	$66.45	$56.90	$34.40
13	$31.90	$47.90	$66.80	$58.05	$62.40	$72.10	$74.55	$70.80	$60.40	$36.60
14	$33.30	$50.20	$70.40	$61.65	$65.70	$76.70	$78.90	$75.15	$63.90	$38.70
15	$34.70	$52.50	$74.00	$65.25	$69.00	$81.30	$83.25	$79.50	$67.40	$40.90
16	$36.10	$54.80	$77.60	$68.85	$72.30	$85.90	$87.60	$83.85	$70.90	$42.90
17	$37.50	$57.10	$81.20	$72.45	$75.60	$90.50	$91.95	$88.20	$74.40	$44.85
18	$38.90	$59.40	$84.80	$76.05	$78.90	$95.10	$96.30	$92.55	$77.90	$46.85
19	$40.30	$61.70	$88.40	$79.65	$82.20	$99.70	$100.65	$96.90	$81.40	$48.85
20	$41.70	$64.00	$92.00	$83.25	$85.50	$104.30	$105.00	$101.25	$84.90	$50.80
21	$43.10	$66.30	$95.60	$86.85	$88.80	$108.90	$109.35	$105.60	$88.40	$52.80
22	$44.50	$68.60	$99.20	$90.45	$92.10	$113.50	$113.70	$109.95	$91.90	$54.80
23	$45.90	$70.90	$102.80	$94.05	$95.40	$118.10	$118.05	$114.30	$95.40	$56.75
24	$47.30	$73.20	$106.40	$97.65	$98.70	$122.70	$122.40	$118.65	$98.90	$58.75
25	$48.70	$75.50	$110.00	$101.25	$102.00	$127.30	$126.75	$123.00	$102.40	$60.70
26	$50.10	$77.80	$113.60	$104.85	$105.30	$131.90	$131.10	$127.35	$105.90	$62.65
27	$51.50	$80.10	$117.20	$108.45	$108.60	$136.50	$135.45	$131.70	$109.40	$64.65
28	$52.90	$82.40	$120.80	$112.05	$111.90	$141.10	$139.80	$136.05	$112.90	$66.60
29	$54.30	$84.70	$124.40	$115.65	$115.20	$145.70	$144.15	$140.40	$116.40	$68.55
30	$55.70	$87.00	$128.00	$119.25	$118.50	$150.30	$148.50	$144.75	$119.90	$70.55
31	$57.10	$89.30	$131.60	$122.85	$121.80	$154.90	$152.85	$149.10	$123.40	$72.50
32	$58.50	$91.60	$135.20	$126.45	$125.10	$159.50	$157.20	$153.45	$126.90	$74.45
33	$59.90	$93.90	$138.80	$130.05	$128.40	$164.10	$161.55	$157.80	$130.40	$76.40
34	$61.30	$96.20	$142.40	$133.65	$131.70	$168.70	$165.90	$162.15	$133.90	$78.35
35	$62.70	$98.50	$146.00	$137.25	$135.00	$173.30	$170.25	$166.50	$137.40	$80.30

PRIORITY MAIL INTERNATIONAL [1]—Continued

Weight not over (pounds)	Rate group 1	Rate group 2	Rate group 3	Rate group 4	Rate group 5	Rate group 6	Rate group 7	Rate group 8	Rate group 9	Rate group 10
36	$64.10	$100.80	$149.60	$140.85	$138.30	$177.90	$174.60	$170.85	$140.90	$82.40
37	$65.50	$103.10	$153.20	$144.45	$141.60	$182.50	$178.95	$175.20	$144.40	$84.50
38	$66.90	$105.40	$156.80	$148.05	$144.90	$187.10	$183.30	$179.55	$147.90	$86.65
39	$68.30	$107.70	$160.40	$151.65	$148.20	$191.70	$187.65	$183.90	$151.40	$88.70
40	$69.70	$110.00	$164.00	$155.25	$151.50	$196.30	$192.00	$188.25	$154.90	$90.80
41	$71.10	$112.30	$167.60	$158.85	$154.80	$200.90	$196.35	$192.60	$158.40	$92.85
42	$72.50	$114.60	$171.20	$162.45	$158.10	$205.50	$200.70	$196.95	$161.90	$94.95
43	$73.90	$116.90	$174.80	$166.05	$161.40	$210.10	$205.05	$201.30	$165.40	$97.05
44	$75.30	$119.20	$178.40	$169.65	$164.70	$214.70	$209.40	$205.65	$168.90	$99.10
45	$76.70	.....	$182.00	$173.25	$168.00	$219.30	$213.75	$210.00	$172.40	$101.20
46	$78.10	.....	$185.60	$176.85	$171.30	$223.90	$218.10	$214.35	$175.90	$103.25
47	$79.50	.....	$189.20	$180.45	$174.60	$228.50	$222.45	$218.70	$179.40	$105.35
48	$80.90	.....	$192.80	$184.05	$177.90	$233.10	$226.80	$223.05	$182.90	$107.45
49	$82.30	.....	$196.40	$187.65	$181.20	$237.70	$231.15	$227.40	$186.40	$109.50
50	$83.70	.....	$200.00	$191.25	$184.50	$242.30	$235.50	$231.75	$189.90	$111.55
51	$85.10	.....	$203.60	$194.85	$187.80	$246.90	$239.85	$236.10	$193.40	$113.65
52	$86.50	.....	$207.20	$198.45	$191.10	$251.50	$244.20	$240.45	$196.90	$115.70
53	$87.90	.....	$210.80	$202.05	$194.40	$256.10	$248.55	$244.80	$200.40	$117.85
54	$89.30	.....	$214.40	$205.65	$197.70	$260.70	$252.90	$249.15	$203.90	$119.90
55	$90.70	.....	$218.00	$209.25	$201.00	$265.30	$257.25	$253.50	$207.40	$122.00
56	$92.10	.....	$221.60	$212.85	$204.30	$269.90	$261.60	$257.85	$210.90	$124.05
57	$93.50	.....	$225.20	$216.45	$207.60	$274.50	$265.95	$262.20	$214.40	$126.15
58	$94.90	.....	$228.80	$220.05	$210.90	$279.10	$270.30	$266.55	$217.90	$128.20
59	$96.30	.....	$232.40	$223.65	$214.20	$283.70	$274.65	$270.90	$221.40	$130.30
60	$97.70	.....	$236.00	$227.25	$217.50	$288.30	$279.00	$275.25	$224.90	$132.35
61	$99.10	.....	$239.60	$230.85	$220.80	$292.90	$283.35	$279.60	$228.40	$134.45
62	$100.50	.....	$243.20	$234.45	$224.10	$297.50	$287.70	$283.95	$231.90	$136.50
63	$101.90	.....	$246.80	$238.05	$227.40	$302.10	$292.05	$288.30	$235.40	$138.65
64	$103.30	.....	$250.40	$241.65	$230.70	$306.70	$296.40	$292.65	$238.90	$140.70
65	$104.70	.....	$254.00	$245.25	$234.00	$311.30	$300.75	$297.00	$242.40	$142.80
66	$106.10	.....	$257.60	$248.85	$237.30	$315.90	$305.10	$301.35	$245.90	$144.85
67	.....	.....	.....	$252.45	$240.60	$320.50	$309.45	$305.70	$249.40	$146.95
68	.....	.....	.....	$256.05	$243.90	$325.10	$313.80	$310.05	$252.90	$149.00
69	.....	.....	.....	$259.65	$247.20	$329.70	$318.15	$314.40	$256.40	$151.10
70	.....	.....	.....	$263.25	$250.50	$334.30	$322.50	$318.75	$259.90	$153.20

[1] Merchandise is permitted, but written communications having the nature of current and personal correspondence are not permitted.

PRIORITY MAIL INTERNATIONAL—FLAT-RATE ENVELOPE [1]

Destination country	Envelope
Canada & Mexico	$9.00
All other countries	$11.00

[1] May contain items which may be sent as First-Class Mail International. The maximum weight is 4 lbs.

PRIORITY MAIL INTERNATIONAL—FLAT-RATE BOX [1]

Destination country	Box
Canada & Mexico	$23.00
All other countries	$37.00

[1] Merchandise is permitted, but written communications having the nature of current and personal correspondence are not permitted. The maximum weight is 20 lbs. or the limit set by the individual country.

ONLINE DISCOUNTS

Service	Global express guaranteed	Express mail international	Priority mail international
Discount	10%	8%	5%

FIRST-CLASS MAIL INTERNATIONAL

Weight not over (oz.)	Rate groups					
	1	2	3	4	5	6
1.0	$0.69	$0.69	$0.90	$0.90	$0.90	$0.61
2.0	$1.00	$1.12	$1.80	$1.80	$1.80	$1.07
3.0	$1.31	$1.55	$2.70	$2.70	$2.70	$1.53
4.0	$1.62	$1.98	$3.60	$3.60	$3.60	$1.99
5.0	$1.93	$2.41	$4.50	$4.50	$4.50	$2.45
6.0	$2.24	$2.84	$5.40	$5.40	$5.40	$2.92
7.0	$2.55	$3.27	$6.30	$6.30	$6.30	$3.38
8.0	$2.86	$3.70	$7.20	$7.20	$7.20	$3.84
12.0	$3.76	$5.10	$8.80	$8.65	$8.65	$5.15
16.0	$4.66	$6.50	$10.40	$10.10	$10.10	$6.21
20.0	$5.56	$7.90	$12.00	$11.55	$11.55	$7.27
24.0	$6.46	$9.30	$13.60	$13.00	$13.00	$8.33
28.0	$7.36	$10.70	$15.20	$14.45	$14.45	$9.39
32.0	$8.26	$12.10	$16.80	$15.90	$15.90	$10.45
36.0	$9.16	$13.50	$18.40	$17.35	$17.35	$11.51
40.0	$10.06	$14.90	$20.00	$18.80	$18.80	$12.57
44.0	$10.96	$16.30	$21.60	$20.25	$20.25	$13.63
48.0	$11.86	$17.70	$23.20	$21.70	$21.70	$14.69
52.0	$12.76	$19.10	$24.80	$23.15	$23.15	$15.75
56.0	$13.66	$20.50	$26.40	$24.60	$24.60	$16.81
60.0	$14.56	$21.90	$28.00	$26.05	$26.05	$17.87
64.0	$15.46	$23.30	$29.60	$27.50	$27.50	$18.93

POSTAL CARDS AND POSTCARDS

Destination country	Postage rate
Canada and Mexico	$0.69
Republic of the Marshall Islands and Federated States of Micronesia	$0.52
All Other Countries	$0.90

INTERNATIONAL PRIORITY AIRMAIL (IPA)

Rate groups	Per piece	Full service per lb.	ISC drop shipment per lb.
1	$0.33	$4.55	$3.55
2	0.15	6.10	5.10
3	0.32	7.50	6.50
4	0.32	7.70	6.70
5	0.15	6.50	5.50
6	0.15	5.80	4.80
7	0.15	7.50	6.50
8	0.12	8.00	7.00
9	0.27	8.25	7.25
Worldwide	0.25	8.50	7.50

INTERNATIONAL PRIORITY AIRMAIL (IPA) M–BAG—FULL SERVICE

Rate groups	Full service per lb.
1	$2.10
2	2.70
3	3.60
4	5.15
5	4.40
6	4.20
7	4.95
8	4.85
9	5.60

Note: M-bags are subject to the minimum rate for 11 pounds.

INTERNATIONAL PRIORITY AIRMAIL (IPA) M–BAG—ISC DROP SHIPMENT

Weight not over (lb.)	Rate groups								
	1	2	3	4	5	6	7	8	9
5	$19.30	$25.00	$30.85	$44.50	$38.75	$38.65	$44.80	$42.50	$47.75
6	19.75	25.60	31.85	46.25	39.90	39.45	45.95	43.85	49.60
7	20.20	26.20	32.85	48.00	41.05	40.25	47.10	45.20	51.45
8	20.65	26.80	33.85	49.75	42.20	41.05	48.25	46.55	53.30
9	21.10	27.40	34.85	51.50	43.35	41.85	49.40	47.90	55.15
10	21.55	28.00	35.85	53.25	44.50	42.65	50.55	49.25	57.00
11	22.00	28.60	36.85	55.00	45.65	43.45	51.70	50.60	58.85
Each additional pound or fraction of a pound	2.00	2.60	3.35	5.00	4.15	3.95	4.70	4.60	5.35

INTERNATIONAL SURFACE AIR LIFT (ISAL)

Rate groups	Per piece	Full service per lb.	Direct shipment per lb.	ISC drop shipment per lb.
1	$0.32	$3.20	$2.70	$2.20
2	0.15	5.15	4.65	4.15
3	0.30	4.00	3.50	3.00
4	0.32	4.35	3.85	3.35
5	0.15	5.45	4.95	4.45
6	0.15	5.55	5.05	4.55
7	0.15	5.45	4.95	4.45
8	0.12	6.60	6.10	5.60
9	0.22	4.45	3.95	3.45

INTERNATIONAL SURFACE AIR LIFT (ISAL) M–BAG—FULL SERVICE AND DIRECT SHIPMENT

Rate groups	Full service per lb.	Direct shipment per lb.
1	$1.60	$1.60
2	1.70	1.70
3	2.00	2.00
4	2.80	2.80
5	2.35	2.35
6	2.35	2.35
7	2.60	2.60
8	3.25	3.25
9	3.00	3.00

Note: M-bags are subject to the minimum rate for 11 pounds.

INTERNATIONAL SURFACE AIR LIFT (ISAL) M–BAG—ISC DROP SHIPMENT

Weight not over (lb.)	Rate groups								
	1	2	3	4	5	6	7	8	9
5	$15.90	$14.30	$11.45	$16.25	$12.90	$14.40	$12.05	$16.20	$18.25
6	16.00	14.85	12.75	18.40	14.60	15.85	14.35	19.00	20.25
7	16.10	15.40	14.05	20.55	16.30	17.30	16.65	21.80	22.25
8	16.20	15.95	15.35	22.70	18.00	18.75	18.95	24.60	24.25
9	16.30	16.50	16.65	24.85	19.70	20.20	21.25	27.40	26.25
10	16.40	17.05	17.95	27.00	21.40	21.65	23.55	30.20	28.25
11	16.50	17.60	19.25	29.15	23.10	23.10	25.85	33.00	30.25
Each additional pound or fraction of a pound	1.50	1.60	1.75	2.65	2.10	2.10	2.35	3.00	2.75

M–BAGS

Rate groups	Weight not over 11 lbs.	Additional per lb.
RG 1 (Canada)	$18.70	$1.70
RG 2 (Mexico)	24.20	2.20
RG 3 (Europe IC/Israel)	31.35	2.85
RG 4 (Japan/Aus/NZ)	49.50	4.50
RG 5 (All Other Countries—retail)	43.45	3.95

EXTRA SERVICES FEES

Service	Fee
International Postal Money Orders	$3.85
International Reply Coupons	$2.00
International Business Reply Card	$0.90
International Business Reply Envelope (up to 2 oz.)	$1.40
Customs Clearance and Delivery Fee	$5.35
Certificate of Mailing	$1.05
Restricted Delivery	$4.10
Registered Mail	$10.15
Return Receipt	$2.15
Pickup On-Demand Fee	$14.25

INSURANCE

Insurance

Priority mail international insurance not over	Canada	All other countries
$50	$1.65	$2.40
$100	$2.05	$3.30
$200	$2.45	$4.20
$300	$4.60	$5.10
$400	$5.50	$6.00
$500	$6.40	$6.90
$600	$7.30	$7.80
$675	$8.20	[1]
$700	[1]	$8.70
[2] Add'l Indemnity	[1]	$0.90

[1] Not Applicable
[2] Each additional $100 or fraction. See individual country listings for maximum indemnity.

GLOBAL EXPRESS GUARANTEED INDEMNITY

Global Express Guaranteed Indemnity not over (U.S. $)	All countries
$100	No fee.
Add'l Indemnity*	$0.75

* Each additional $100 or fraction. See individual country listings for maximum indemnity.

EXPRESS MAIL INTERNATIONAL MERCHANDISE INSURANCE

Amount of coverage	Fee
$ 0.01 to $100.00	$0.00
100.01 to 200.00	0.75
200.01 to 500.00	2.10
500.01 to 1,000.00	3.45
1,000.01 to 1,500.00	4.80
1,500.01 to 2,000.00	6.15
2,000.01 to 2,500.00	7.50
2,500.01 to 3,000.00	8.85

EXPRESS MAIL INTERNATIONAL MERCHANDISE INSURANCE—Continued

Amount of coverage	Fee
3,000.01 to 3,500.00	10.20
3,500.01 to 4,000.00	11.55
4,000.01 to 4,500.00	12.90
4,500.01 to 5,000.00	14.25

■ 3. Revise the Mailing Standards of the United States Postal Service, International Mail Manual (IMM), as follows:

* * * * *

1 International Mail Services

110 General Information

* * * * *

112 Mailer Responsibility

[Revise 112 by adding the following after the last sentence.]

* * * Full responsibility rests with the mailer to comply with all postal and nonpostal laws and regulations regarding the mailing of dangerous goods. Anyone who mails, or causes to be mailed, nonmailable or improperly packaged dangerous goods can be subject to legal penalties, including but not limited to those specified in 18 U.S.C.

115 Official Correspondence

115.1 Communicating With Headquarters

* * * * *

115.13 Transportation and Distribution

[Revise the first sentence of 115.13 as follows:]

Correspondence concerning the transportation of international civil and military mail, including the following, should be addressed to:

* * * * *

120 Preparation for Mailing

* * * * *

122 Addressing

122.1 Destination Address

[Revise 122.1d by changing the reference to 284.1 to 292.41.]

* * * * *

123 Customs Forms

123.1 General

* * * * *

[Revise the Note for 123.1 as follows:]

Note: The current edition of PS Form 2976 is January 2004; the current edition of PS Form 2976-A is January 2006; the current edition of PS Form 2976-E is September 2006. Except as provided in 123.3, mailers must present at the time of mailing a fully completed Sender's Declaration (the Post Office copy of PS Form 2976 or 2976–A), which specifies both the sender's name and address and the addressee's name and address.

* * * * *

123.5 Place of Mailing

[Revise the exception by changing the reference to ''Global Express Mail'' to Express Mail International.]

123.6 Required Usage

123.61 Conditions

* * * * *

[Revise Exhibit 123.61 as follows:]

Exhibit 123.61

CUSTOMS DECLARATION FORM USAGE

Mail category	Declared value	Required form	Comment
Global Express Guaranteed	All values	Mailing label (item 11FGG1).	GXG Customs Form, PS Form 6182, Commercial Invoice as specified in the individual country listings.
Express Mail International	All values	2976 or 2976–A	Required Customs Forms and endorsements vary by country and are specified in the Individual Country Listings.
Priority Mail International	All values	2976–A with 2976–E	All items mailed in Priority Mail International packaging boxes, containers, flats, and envelopes, except the Priority Mail flat-rate envelope, and any item bearing a Priority Mail sticker or marked with the words ''Priority Mail'' is considered a parcel. Do not use PS Form 2976 (green label) on Priority Mail International parcels.
Priority Mail Flat-Rate Envelope items that: Weigh less than 16 ounces and do not have potentially dutiable contents or weigh less than 16 ounces and have potentially dutiable contents with a declared value less than $400.	Under $400	2976*	May contain personal correspondence including letters, documents, printed matter, and light-weight merchandise items. Merchandise is permitted unless prohibited by the destination country. The maximum weight limit is 4 lbs.
Weigh 16 ounces or more, regardless of contents, regardless of value.	Regardless of value	2976–A*.	
First Class Mail International items that: Weigh less than 16 ounces and do not have potentially dutiable contents.	N/A	None	A known mailer, as defined in 123.62, may be exempt from affixing customs forms to nondutiable mailpieces that weigh 16 ounces or more.
Weigh 16 ounces or more; do not have potentially dutiable contents; and are entered by a known mailer.			
First Class Mail International items that: Weigh less than 16 ounces and have potentially dutiable contents.	Under $400 $400 and over	2976* 2976–A*.	
Weigh 16 ounces or more, regardless of contents, regardless of value.	Regardless of value	2976–A*.	
Free matter for the blind	Under $400 $400 or more	2976* 2976–A with 2976–E*.	
M-bag	Under $400 $400 or more	2976* 2976–A*.	
(Note: An M-bag requires a customs form when it contains potentially dutiable printed matter, and admissible merchandise items as defined in 261.22 or some combination thereof.).			

*Placement of forms: Use PS Form 2976 (green label) for Priority Mail International flat-rate envelope and First-Class Mail International items under $400 in value and affix it to the outside of the package. If the value of the contents is $400 or more, affix the upper portion of PS Form 2976 (green label) (cut on dotted line and discard the lower portion) to the outside of the package, complete a separate PS Form 2976–A, and enclose the form set inside the package.

* * * * *

[Revise the heading of the notes and delete notes 1 and 3 as follows:]

Note: Bulk business products, including International Surface Air Lift * * *

* * * * *

123.62 Known Mailers

* * * * *

[Revise the ''Exception'' by changing the references to 292.222 and 293.92 to 292.22 and 293.75.]

* * * * *

123.7 Completing Customs Forms

123.71 PS Form 2976, Customs Declaration CN22—Sender's Declaration (green label)

123.711 Sender's preparation of PS Form 2976

[Revise 123.711 by adding new e and re-alphabetizing current e through j as f through k.]

e. The sender must enter the actual value of an item for registered items in a consistent manner on Forms 3806 and 2976, i.e., the value entered must be identical. Items on which identical values are not declared will be refused. (See IMM 334.12)

* * * * *

123.72 PS Form 2976–A, Customs Declaration and Dispatch Note—CP 72

123.721 Sender's Preparation of PS Form 2976–A

* * * * *

o. Affix PS Form 2976–A according to the class of mail, as follows:

[Revise item o(1) as follows:]

(1) For Priority Mail International parcels, with the exception of the flat-rate envelope, first allow the Postal Service employee to complete PS Form 2976–A as described in *123.722* and then place the form set inside PS Form 2976–E (plastic envelope) and affix it to the outside of the package.

[Revise item o(2) as follows]

(2) For a Priority Mail International flat-rate envelope or First-Class Mail International item valued at $400 or more, or if you do not want to list the contents on the outside wrapper of a Priority Mail International flat-rate envelope or First-Class Mail International item, affix the upper portion of PS Form 2976 (green label) (cut on dotted line and discard the lower portion) to the address side of the package, complete PS Form 2976–A, and enclose the form set inside the package.

* * * * *

130 Mailability

131 General

131.1 Domestic Limits

131.2 International Limits

[Revise 131.2 by changing the reference to section 630 to section 6.]

* * * * *

134 Valuable Articles

134.1 List of Articles

[Revise 134.1 as follows:]

The following valuable articles may be sent only by registered Priority Mail International flat-rate envelope, registered First-Class Mail International, or by insured Priority Mail International shipments and are not mailable in Express Mail International or ordinary Priority Mail International shipments (see 221.2 and 233):

* * * * *

135 Mailable Dangerous Goods

135.1 Biological Substances

135.11 General Conditions

[Revise 135.11 as follows:]

Infectious substances are acceptable in the international mail subject to the provisions of DMM 601 and under the additional conditions specified in subsections below.

[Revise 135.12 by changing airmail letter-post to First-Class Mail International.]:

* * * * *

135.2 Authorization

* * * * *

135.22 Requests for Authorization

[Revise the first sentence of 135.22 as follows:]

Qualifying institutions wishing to mail packages containing biological substances must submit a written request on their organizational letterhead to the following address:

* * * * *

135.4 Marking

135.41 Infectious Biological Substances

[Revise the first sentence of 135.41 as follows:]

Items that contain infectious biological substances should be identified by a black and white diamond-shaped label with the division number 6.2 in the bottom, in addition to the Etiologic Agents/Biohazard Material label. * * *

* * * * *

135.42 Noninfectious Biological Substances

[Revise the first sentence of 135.42 as follows:]

Items that contain noninfectious biological substances must be identified by a violet-colored label bearing the prescribed symbol and French wording for perishable biological materials: ''MATIERES BIOLOGIQUES PERISSABLES.''

* * * * *

135.5 Handling and Dispatch

135.51 Biological Substances

[Revise 135.51 as follows:]

Items that contain perishable biological substances must be given careful yet expeditious handling from receipt through dispatch.

* * * * *

135.6 Radioactive Materials

* * * * *

[Revise item a as follows:]

a. Shipments may be sent only by registered First-Class Mail International.

* * * * *

139 Perishable Matter

139.1 Animals

* * * * *

c. Parasites and predators of injurious insects, if the following conditions are met:

* * * * *

[Revise item c (4) as follows:]

(4) They are sent by First-Class Mail International.

* * * * *

139.3 Eggs

139.31 Restrictions

[Revise 139.31 as follows:]

Eggs may be sent only by Priority Mail International.* * *

* * * * *

140 International Mail Categories

141 Definitions

141.1 General

[Revise 141.1 as follows:]

There are four principal categories of international mail that are primarily differentiated from one another by speed of service. They are Global Express Guaranteed®(GXG), Express Mail International service, Priority Mail International, and First-Class Mail International service.

* * * * *

[Revise the title and text of 141.3 as follows:]

141.3 Express Mail International

The next level of service, in terms of speed and value-added features, is Express Mail International. Express Mail International is an expedited mail service that can be used to send documents and merchandise to most of the country locations that are individually listed in this publication. Express Mail International insurance coverage against loss, damage, or rifling, up to a maximum of $100, is provided at no additional charge. Additional merchandise insurance coverage up to $5,000 may be purchased at the sender's option to many countries. Document reconstruction insurance coverage is limited to a maximum of $100 per shipment. Return receipt service is available upon request, at no additional

charge, for Express Mail International shipments that are sent to a limited number of countries. See 221.4. Country-specific maximum weight limits range from 22 pounds to 70 pounds. See the Individual Country Listings. Express Mail International shipments offers a date-certain, money-back guarantee to select destinations: see IMM 221.1 and the Individual Country Listings to determine the availability of such service. For all other destinations, Express Mail International shipments are not subject to a postage refund guarantee if a delivery delay occurs.

[Revise 141.4 as follows:]

141.4 Priority Mail International

a. With the exception of the flat-rate envelope, Priority Mail International, which is referred to as CP mail, is governed by the parcels provisions of the Universal Postal Convention. That classification is primarily designed to accommodate larger and heavier shipments, whose size and/or weight transcend the established limitations for First-Class Mail International. At the sender's option, extra services, such as insurance coverage and return receipt service may be added on a country specific basis.

b. Priority Mail International flat-rate envelope is an accelerated airmail service that provides customers with a reliable and economical means of sending correspondence, documents, printed matter, and light-weight merchandise items to foreign destinations. The maximum limit is 4 pounds. Registered Mail service is available for the Priority Mail International flat-rate envelope. Insurance is not available in combination with Priority Mail International flat-rate envelope service.

[Revise the title and text of 141.5 as follows:]

141.5 First-Class Mail International

First-Class Mail International is a generic term for mailpieces of differing shapes, sizes, and contents which weigh four pounds or less that are subject to the provisions of the Universal Postal Union letter-post Convention. First-Class Mail International items may contain any mailable matter that is not hazardous or prohibited by the destination country. Aerogrammes are not available for purchase. Previously purchased aerogrammes are mailable at the applicable First-Class Mail International rate. At the sender's option, extra services, such as registry and return receipt may be added on a country-specific basis.

Note: The term First-Class Mail International encompasses all of the classes of international letter-post mail (i.e., letter and letter packages, postcards and postal cards, printed matter, and small packets) that were formerly categorized as LC (letters and cards) and AO (other articles) respectively.

[Delete 141.6.]

* * * * *

142 Envelope and Card Specifications

* * * * *

142.6 Bordered Envelopes and Cards

[Revise 142.6 by changing airmail letter-post to First-Class Mail International.]

143 Official Mail

* * * * *

143.4 General Secretariat of the Organization of American States (OAS)

[Revise items a and b as follows:]

a. Unregistered First-Class Mail International items bearing the return address of the OAS General Secretariat and weighing not more than 4 pounds are accepted without postage when addressed to the OAS member countries listed in *143.4*c.

b. Items other than First-Class Mail International with extra services may not be provided for OAS General Secretariat official mail without the prepayment of postage or the fee for the extra service requested.

* * * * *

143.5 Pan American Sanitary Bureau Mail

[Revise items a and b as follows:]

a. Unregistered First-Class Mail International items bearing the return address of the bureau and weighing not more than 4 pounds, are accepted without postage affixed when addressed to an OAS member country listed in *143.4c* or to Cuba.

b. Items with the bureau return address that are sent other than First-Class Mail International or that requests extra services must prepay all postage and fees.

150 Postage

* * * * *

152 Payment Methods

* * * * *

152.2 Stamps

* * * * *

[Revise item a by changing special services to extra services. Delete item c, and re-letter current item d as new item c and revise as follows:]

c. Nondenominated postage stamps (except for those that bear unique domestic markings, such as First-Class Presort, Nonprofit Org.) may be affixed to postal items that are sent to foreign countries. The value of such stamps is linked to either a current or a former domestic rate (e.g., the ''Lady Liberty and U.S. Flag'' stamp has a postage value of 39 cents). The postage value of the Forever Stamp, as well as the nondenominated Breast Cancer Research semipostal stamp, is always the domestic First-Class Mail single-piece one-ounce letter rate that is in effect on the day of use (mailing). Since international postage rates are always higher than the comparable domestic postage rates, mailers who affix a single nondenominated postage stamp to their outbound mailpieces must add additional postage to comply with the international rate schedule.

* * * * *

152.3 Permit Imprint

152.31 Conditions of Use

[Revise 152.31 as follows:]

Postage may be paid by permit imprint, subject to the general conditions stated in DMM 124, 604, and 705. Postage charges are computed on PS Form 3700. This postage payment method may be used for postage and extra service fees for First-Class Mail International and Priority Mail International.

* * * * *

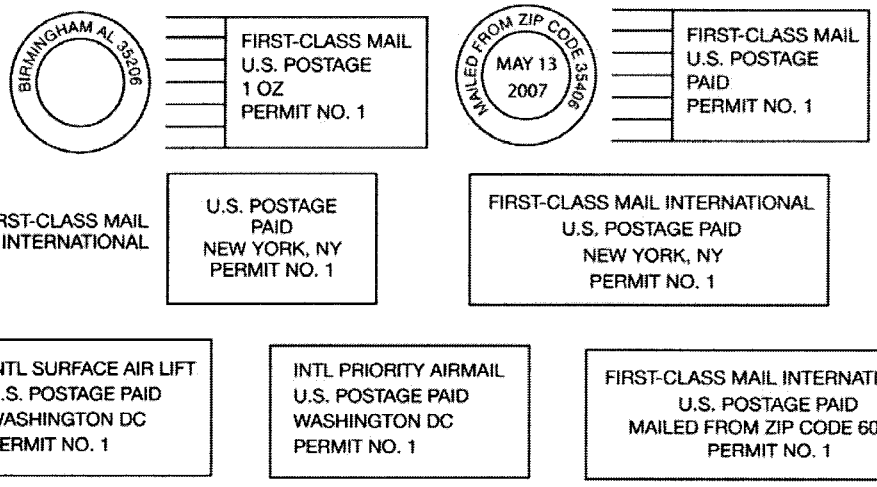
[Revise Exhibit 152.34 as follows:]

Exhibit 152.34

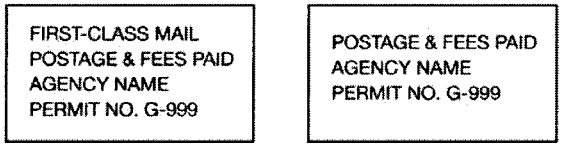
Indicia Formats

BILLING CODE 7710–12–P

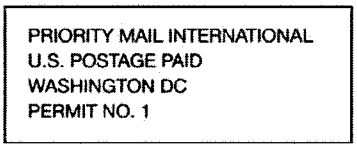
FIRST-CLASS MAIL INTERNATIONAL (Includes IPA, ISAL, and M-Bags)



OFFICIAL MAIL



PRIORITY MAIL INTERNATIONAL



BILLING CODE 7710–12–C

[Delete 152.4.]

2 Conditions for Mailing

210 Global Express Guaranteed

211 Description

* * * * *

[Revise the title of 211.2 as follows:]

211.2 Eligibility

* * * * *

[Insert new 211.3 as follows:]

211.3 Global Express Guaranteed Service

Global Express Guaranteed (GXG) service may be used for shipments that contain documents and general correspondence for which no duty is assessed by the customs authority of the destinating country, or for shipments that contain non-documents, or other merchandise for which duty may be assessed by the customs authority of the destinating country. Document packages are sealed against inspection by the Postal Service or other U.S. agencies and authorities. Shipments that contain non-documents or other merchandise for which duty may be assessed by the customs authority of the destinating country are not sealed against inspection under 39 U.S.C. 3623(d). These shipments are also subject to inspection by the Postal Service and its designated agents for purposes of aviation (air) security, and to determine that the contents are eligible for mailing and that the contents are adequately declared on the Global Express Guaranteed Air Waybill/Shipping Invoice to permit expedited customs clearance. All shipments (documents and non-documents) may also be subject to inspection in the destinating country for purposes of compliance with the customs requirements of the destinating country. See the listing of destinating countries in 213 for specific availability.

[Delete current 212.2.]

[Insert current 216 title as new 212 title, and revise as follows:]

212 Postage Rates

[Insert current 216.1 (with new rates and rate groups) as new 212.1, and change title to ''Global Express Guaranteed Service Rates/Groups''.]

[Delete current 216.2 in its entirety.]

[Insert current 216.3 in its entirety as new 212.2.]

* * * * *

212.2 Discounted Rates

* * * * *

212.23 Online Discounts

212.231 General

[Revise the last line of new 212.231 as follows:]

* * * The discounted postage rates applicable to Global Express Guaranteed are set forth in 212.26 and are separate and distinct from the postage rates set forth in 212.1.

212.232 Standard Web Discount

[Revise text in 212.232 as follows]

Discounted rates apply to Global Express Guaranteed mailings that do not qualify for the volume discount schedule and the customer prepares and pays for Global Express Guaranteed shipments online at usps.com or by

using an authorized PC Postage vendor. Global Express Guaranteed published rates will be reduced by 10 percent for all payments at USPS.com or made through an authorized PC Postage vendor. The discount applies only to the postage portion of Global Express Guaranteed rates. It does not apply to the pickup service charge or additional insurance fees. The discount is automatically applied to each shipment.

* * * * *

[Revise new 212.252 (current 216.352 item a by changing ''$13.25'' to ''$14.25.''] [Revise title of new 212.261(current 216.361) to ''Global Express Guaranteed with Standard Web Discount'' (Discounts apply only to customers who pay for postage online.) (New table includes new prices and rate groups.]

[Delete 216.362 in its entirety.]

[Delete 216.363 in its entirety.]

[Delete 216.364 in its entirety.]

[Insert current 216.4 in its entirety as new 212.3.]

* * * * *

213 Service Areas

* * * * *

213.2 Destinating Countries and Rate Groups

* * * * *

[In the table, Delete the ''Non-Document Service Rate Group'' column and revise the title of the ''Document Service Rate Group'' column to be ''GXG Rate Group''.]

* * * * *

[Revise the introductory text before the last group of countries in 213.2 as follows:]

Only documents (211.3) may be sent to the following countries:

* * * * *

213.3 Pickup Service

[Revise the 213.3 as follows:]

a. On-call and scheduled pickup services are available for an added charge of $14.25 for each pickup stop, regardless of the number of pieces picked up. Only one pickup fee will be charged if domestic Express Mail, Express Mail International, domestic Priority Mail, Priority Mail International, and/or domestic Parcel Post is picked up at the same time.

b. No pickup fee will be charged when Global Express Guaranteed is picked up during a delivery stop or during a scheduled stop made to collect other mail not subject to a pickup fee. Pickup service is provided in accordance with the information in DMM 507.5; for more information, also visit the online site at *usps.com/pickup.*

214 Service Guarantee

* * * * *

[Revise the title and text of 214.2 as follows:]

214.2 Transit Days for Shipments Containing Non-Documents

Total transit days for Global Express Guaranteed service for non-document items, may be affected by general customs delays, specific customs commodity delays, holidays observed in the destinating country, and other factors beyond the Postal Service's control. See the Terms and Conditions on the Global Express Guaranteed Air Waybill/Shipping Invoice or in Publication 141 for details.

215 Inquiries, Postage Refunds, and Indemnity Claims

* * * * *

215.3 Indemnity Claims

[Delete the titles for 215.31 and 215.32 and revise the text for 215.3 as follows:]

If a shipment is lost or damaged, the sender may file a claim for document reconstruction costs (for document items), or for the declared value of the shipment costs (for non-document items). All claims must be initiated within 30 days of the shipment date by contacting a customer service representative at 800–222–1811. The representative will provide more details on how to file a claim. The original receipt of the Global Express Guaranteed Air Waybill/Shipping Invoice must be included when filing a claim. Consult Publication 141 for limitations and restrictions on indemnity payments for Global Express Guaranteed items. The Global Express Guaranteed customer service office will adjudicate refunds for Global Express Guaranteed. The Global Express Guaranteed customer service office can be contacted at 800–222–1811. Final approval and payment will be made by the Postal Service.

215.4 Extent of Postal Service Liability for Lost or Damaged Contents

[Delete the titles for 215.41 and 215.42 and revise the text for 215.4 as follows:]

Liability for a lost or damaged Global Express Guaranteed shipment is limited to the lowest of the following:

a. $100 or the amount of additional optional insurance purchased.

b. The actual amount of the loss or damage.

c. The actual value of the contents.

''Actual value'' means the lowest cost of replacing, reconstructing or reconstituting the allowable contents of the shipment (determined at the time and place of acceptance). See individual country listings.

215.5 Insurance

[Revise the title and text of 215.51 as follows:]

215.51 Insurance for Global Express Guaranteed

Document reconstruction insurance (the reasonable costs incurred in reconstructing duplicates of nonnegotiable documents mailed), and non-document insurance for loss or damage up to $100 per shipment, is included at no additional charge (See individual country listings for availability). Additional insurance may be purchased for non-document and document shipments, as outlined in section 215.52, not to exceed the total cost of reconstruction, $2,499, or a lesser amount as limited by country, content, or value. Coverage, terms, and limitations are subject to change.

[Delete title and text of 215.52 and renumber 215.53 as 215.52.]

* * * * *

[Delete current 216. Renumber current 217 and 218 as 216 and 217.]

216 Sizes and Weights

[Revise 216.1 as follows:]

The weight, dimensional weight, and size limits set forth in this section are for Global Express Guaranteed service shipments containing documents and non-documents unless otherwise noted in the Individual Country Listings.

* * * * *

216.3 Dimensional Weight

[Revise 216.3 as follows:]

Postage for Global Express Guaranteed is charged based on the actual weight or the dimensional weight (as calculated in 216.31 or 216.32), whichever is greater. The equation for determining dimensional weight is as follows:

216.31 Determining Dimensional Weight for a Rectangular Shaped Parcel

Follow these steps to determine the dimensional weight for a rectangular shaped parcel:

a. Determine the length, width, and height in inches. Round off each measurement to the nearest whole inch.

b. Multiply the length by the width by the height.

c. Divide the result by 166 and round up to the next whole number to determine the dimensional weight in pounds.

216.32 Determining Dimensional Weight for a Nonrectangular Shaped Parcel

Follow these steps to determine the dimensional weight for a nonrectangular-shaped parcel:

a. Determine the length, width, and height in inches. Measure the length, width, and height at their extreme dimensions. Round off each measurement to the nearest whole inch.

b. Multiply the length by the width by the height.

c. Multiply the result by an adjustment factor of 0.785.

d. Divide the result by 166 and round up to the next whole number to determine the dimensional weight in pounds.

* * * * *

218 Preparation Requirements

218.1 Preparation by the Sender

[Revise 218.1c as follows. Delete 218.1d.]

c. Complete the Shipment Details to show the contents in detail. For documents, include the estimated cost of reconstruction. For non-documents, include a valuation and country of manufacture. Non-document shipments can not have a value that exceeds $2499. All Global Express Guaranteed shipments must be signed and dated on the mailer agreement,

* * * * *

[Revise the title and text of 220 as follows:]

220 Express Mail International

[Throughout 220, change ''Global Express Mail,'' ''Global Express Mail (EMS),'' and ''EMS'' to ''Express Mail International.'']

221 Description

* * * * *

[Revise the title and first line of 221.2 as follows:]

221.2 Eligibility

Any item not prohibited in international mail is allowed in Express Mail International except dangerous goods. * * *

* * * * *

221.31 Express Mail International Merchandise Insurance

Express Mail International merchandise insurance coverage against loss, damage, or rifling is provided up to $100 at no additional charge. Additional insurance coverage above $100 may be purchased at the sender's option. The fee for optional Express Mail International merchandise insurance coverage is $0.75 up to $200.00; $2.10 for $200.01 to $500.00; and plus $1.35 for each $500 or fraction thereof over $500.00. See individual country listings for merchandise insurance limits.

* * * * *

222 Postage

222.1 Rates

222.11 Country Rates

* * * * *

[Add new Exhibit 222.11 as follows:]

Exhibit 222.11

FLAT-RATE ENVELOPE POSTAGE RATES

Canada & Mexico	$22.00
All other countries	$25.00

222.13 Online Rates—General

[Revise 222.13 as follows:]

Discounted rates apply to Express Mail International customers who prepare and pay for Express Mail International shipments online at usps.com or by using an authorized PC Postage vendor.

* * * * *

222.132 Online Discounts

[Revise 222.132 as follows:]

Express Mail International published rates will be reduced by 8 percent for all payments at USPS.com or made through an authorized PC Postage vendor. The discount applies only to the postage portion of Express Mail International rates. It does not apply to the pickup service charge, additional merchandise insurance fees, or shipments made under an International Customized Mail agreement.

222.2 Payment of Postage

222.21 Methods of Payment

[Revise 222.21 as follows:]

Express Mail International may be paid by postage stamps, postage validation imprinter (PVI) labels, postage meter stamps, information-based indicia (IBI), PC Postage™, or through the use of an Express Mail corporate account.

* * * * *

222.24 Pickup Service

[Revise 222.24 by changing $13.25 to $14.25.]

[Revise the title of 223 as follows:]

223 Physical Characteristics

* * * * *

[Revise the title of 223.2 as follows:]

223.2 Dimensions

* * * * *

[Revise the title of 224 as follows:]

224 Mail Preparations

* * * * *

[Revise the title and text of 230 as follows:]

230 Priority Mail International

231 Description

231.1 General

Priority Mail International is a priority airmail service that provides customers with a reliable and economical means of sending correspondence, documents, printed matter, light-weight merchandise items, and parcels to foreign destinations. Written correspondence having the nature of current and personal correspondence is not permitted in Priority Mail International parcels, but may be sent in the Priority Mail International flat-rate envelope.

231.2 Priority Mail International Flat Rate Envelope

All items which may be sent as First-Class Mail International (see 241) may be sent in the Priority Mail International flat-rate envelope provided that the contents are mailable and fit securely in the envelope and the contents are entirely confined within the envelope with the adhesive provided as the means of closure. The envelope flaps must be able to close within the normal folds. Tape may be applied to the flap and seams for closure or to reinforce the envelope, provided the design of the envelope is not enlarged by opening the sides of the envelope and taping or reconstructing the envelope in any way. Registered mail service is available. Insurance is not available.

232 Priority Mail International Flat-Rate Envelope Postage

232.1 Rates

The Priority Mail International flat-rate envelope is charged at a flat rate. The price does not depend on the weight of the item. Postage is required for each piece. Priority Mail flat-rate envelopes with prepaid postage may be used for international mail. Appropriate additional postage must be added prior to mailing. (See Exhibit 232.1.)

Exhibit 232.1

FLAT-RATE ENVELOPE POSTAGE RATES

Canada & Mexico	$9.00
All other countries	$11.00

232.2 Weight Limit

The weight limit for the flat-rate envelope is 4 pounds.

232.3 Customs Forms Required

All Priority Mail International flat-rate envelopes must bear PS Form 2976 or 2976–A depending on weight and value.

* * * * *

233 Priority Mail International Parcels

233.1 Indemnity

Ordinary Priority Mail International—i.e. uninsured—includes indemnity coverage against loss, damage, or rifling up to the amounts shown in Exhibit 233.3. Indemnity is limited to the lesser of the actual value of the contents or the maximum indemnity based on the weight of the article. If the parcel has been delivered to the addressee, payment for damage and missing contents is made to the addressee unless the addressee waives payment, in writing, in favor of the sender.

Note: International insured mail service provides insurance coverage higher than the indemnity limits for ordinary Priority Mail International parcels to many countries. See IMM 320 and individual country listings for availability and limitations of coverage. When international insurance is purchased, it replaces the ordinary indemnity coverage.

Note: Priority Mail International parcels may be insured, but not the Priority Mail Flat-Rate envelope. (see 322).

233.2 Exclusions

Ordinary indemnity coverage is not paid for:

a. Parcels containing coins; banknotes; currency notes, including paper money; securities of any kind payable to the bearer; traveler's checks; platinum, gold, and silver; precious stones; jewelry; watches; and other valuable articles.

b. Consequential losses, delay, concealed damage, spoilage of perishable items, articles improperly packaged, articles too fragile to withstand normal handling in the mail, or prohibited articles.

c. Priority Mail International parcels mailed to the Republic of the Marshall Islands or the Federated States of Micronesia.

233.3 Ordinary Priority Mail International Weight and Indemnity Limits

Exhibit 233.3 lists the weight and indemnity limits for ordinary Priority Mail International parcels.

Exhibit 233.3

ORDINARY PRIORITY MAIL INTERNATIONAL WEIGHT AND INDEMNITY LIMITS

Weight not over (lbs.)	Indemnity	Weight not over (lbs.)	Indemnity
1	$61.28	36	$165.58
2	$64.26	37	$168.56
3	$67.24	38	$171.54
4	$70.22	39	$174.52
5	$73.20	40	$177.50
6	$76.18	41	$180.48
7	$79.16	42	$183.46
8	$82.14	43	$186.44
9	$85.12	44	$189.42
10	$88.10	45	$192.40
11	$91.08	46	$195.38
12	$94.06	47	$198.36
13	$97.04	48	$201.34
14	$100.02	49	$204.32
15	$103.00	50	$207.30
16	$105.98	51	$210.28
17	$108.96	52	$213.26
18	$111.94	53	$216.24
19	$114.92	54	$219.22
20	$117.90	55	$222.20
21	$120.88	56	$225.18
22	$123.86	57	$228.16
23	$126.84	58	$231.14
24	$129.82	59	$234.12
25	$132.80	60	$237.10
26	$135.78	61	$240.08
27	$138.76	62	$243.06
28	$141.74	63	$246.04
29	$144.72	64	$249.02
30	$147.70	65	$252.00
31	$150.68	66	$254.98
32	$153.66	67	$257.96
33	$156.64	68	$260.94
34	$159.62	69	$263.92
35	$162.60	70	$266.90

234 Priority Mail International Postage

234.1 Priority Mail International—Flat-Rate Box

Exhibit 234.1

Canada and Mexico	$23.00
All other countries	$37.00

Note: Indemnity for items mailed in flat-rate boxes are based on the weight and indemnity limits shown in Exhibit 233.3. Maximum weight limit for the Priority Mail International flat rate box is 20 pounds or the maximum weight allowed by the country of destination whichever is less. See individual country listings.

234.2 Priority Mail International Parcels

Prices for parcels not using a flat-rate box vary by weight and country rate group. See individual country listings.

234.3 Mailing Locations

Parcels may be presented for mailing at any Post Office window.

234.4 Pickup Service

Scheduled pickup service is available for an added charge of $14.25 for each pickup stop regardless of the number of pieces picked up. Only one pickup fee will be charged if domestic Express Mail, Express Mail International, domestic Priority Mail, Priority Mail International, Global Express Guaranteed, and/or domestic Parcel Post are also picked up at the same time. No pickup fee will be charged when Priority Mail International is picked up during a delivery stop or during a scheduled stop made to collect other mail not subject to a pickup fee. Pickup service is provided in accordance with the information in DMM 507.5; for more information, also visit the online site at *usps.com/pickup.*

234.5 Priority Mail International Online Rates

A discount of 5 percent will be applied to Priority Mail International published postage rates for transactions conducted on Click-N-Ship or through an authorized PC postage vendor. The discount applies only to the postage portion of Priority Mail International rates. It does not apply to pickup service charges, insurance fees, or shipments made under an International Customized agreement.

235 Weight and Size Limits

235.1 Weight Limits

a. Flat-rate envelope: 4 lbs.

b. Flat-rate box: 20 lbs.

c. Parcels: See Individual Country Listings.

235.2 Size Limits

235.21 Rectangular Parcels

a. Minimum length and width: 5½ × 3½ inches.

b. Maximum length: 42 inches.

c. Maximum length and girth combined: 79 inches.

235.22 Circular Parcels

Maximum girth (measured along diameter): 64 inches.

235.23 Exceptional Size Limits

The maximum size limit for rectangular-shaped parcels of 42 inches in maximum length and 79 inches in maximum length and girth combined applies to all countries except as follows:

a. Maximum length and girth combined: 108 inches.

Canada
Hong Kong

b. Maximum length: 60 inches

Maximum length and girth combined: 108 inches.

Azerbaijan
Great Britain and Northern Ireland
Japan
Macao
Republic of the Marshall Islands
Federated States of Micronesia
New Zealand

c. Priority Mail International parcels:

Maximum length: 60 inches.

Maximum length and girth combined: 108 inches.

Andorra
Austria
Belgium
Denmark
Finland
France
Germany
Gibraltar
Greece
Ireland
Italy
Liechtenstein
Luxembourg
Malta
Netherlands
Norway
Poland
Portugal
San Marino
Slovak Republic (Slovakia)
Spain
Sweden
Switzerland
Vatican City

236 Preparation Requirements

236.1 Addressing

Name and address of sender and addressee must also be recorded on a separate slip enclosed in the parcel. See 122.

236.2 Marking

Parcels that are paid for at the Priority Mail International rate of postage must be marked ''AIRMAIL'' or ''PAR AVION'' or bear one of the two prescribed airmail labels (i.e., either PS Label 19–A or PS Label 19–B). The airmail marking or label should be placed below and to the left of the delivery address.

236.3 Sealing

236.31 Requirements

All international parcels must be sealed.

236.32 Sealing Materials

Senders must seal their own parcels. Wax, gummed-paper tape, nails, screws, wire, metal bands, or other materials may be used to seal parcels. The seal must be sufficient to allow detection of tampering.

236.4 Packaging

236.41 Packaging Requirements

Every parcel must be securely and substantially packed. In packing, the sender must consider the nature of the contents, the climate, the length of the journey, and the numerous handlings involved in the conveyance of international mail.

236.42 Types of Containers

Ordinary paperboard containers are not acceptable. Parcels must be packed in one of the following:

a. Canvas or similar material.

b. Double-faced corrugated or solid (minimum 275-pound test) fiber boxes or cases.

c. Strong wooden boxes made of lumber at least ½-inch thick or plywood of at least three plies.

236.43 Use of Wrapping Paper

Heavy wrapping paper or waterproof paper is permitted only as the outside covering of a carton.

236.44 Boxes With Screwed or Nailed Lids

If otherwise acceptable, boxes with screwed- or nailed-on lids and bags closed by sewing may be used. Heavy objects, such as cans of food, must be surrounded with other contents or packing material in order to prevent their shifting within the parcel. For illustrations or recommended packing procedures, see DMM 601.

236.45 Customs Forms Required

All Priority Mail International parcels must bear PS Form 2976–A.

236.46 Nonpostal Documentation

Forms required by nonpostal export regulations are described in chapter 5.

* * * * *

[Revise the title of 240 as follows:]

240 First-Class Mail International

[Throughout 240 change the term ''letter-post'' to First-Class Mail International and delete references to ''airmail and economy.'']

241 Description

[Revise the title and text of 241.1 as follows:]

241.1 General

The First-Class Mail International classification encompasses all the classes of international mail that were formerly categorized as airmail letter-post and economy letter-post, post and postal cards, printed matter and small packets that were formerly categorized as LC (letters and cards), and AO (other articles).

* * * * *

242 Postage

242.1 Rates

[Revise the introductory text of 242.1 and the note as follows:]

The country-specific rate group designations that apply to First-Class Mail International and airmail M-bags (see 260) are as follows: * * *

Note: See the Individual Country Listings for the First-Class Mail International postage rates that are applicable to specific destination countries and territorial possessions.

242.2 Payment of Postage

[Revise the text of 242.2 as follows:]

A mailer of a First-Class Mail International item may pay postage with postage stamps, postage meter, postage validation imprinter (PVI) label, PC postage, or permit imprint.

[Revise the title of 243 as follows:]

243 Physical Characteristics

* * * * *

[Revise the title of 243.2 as follows:]

243.2 Dimensions

* * * * *

243.24 Nonmachinable Surcharge

[Revise the introductory text of 243.24 as follows:]

A $0.17 per-piece surcharge is applied to a First-Class Mail International item that weighs 1 ounce or less, if it has one or more of the following characteristics:

* * * * *

[Revise the title of 244 as follows:]

244 Mail Preparation

* * * * *

244.2 Marking

[Revise items a and b by replacing ''Letter-post'' with ''First-Class Mail International;'' revise item d by replacing ''Economy (surface)'' with ''First-Class Mail International''; delete item c and re-letter items d and e as items c and d.]

* * * * *

244.5 Customs Forms Required

244.51 Dutiable Merchandise

* * * * *

[Revise the title of 250 as follows:]

250 Postcards and Postal Cards

251 Description

[Delete the title of 251.1. Renumber current 251.11 and 251.12 as new 251.1 and 251.11.]

251.1 General

[Revise the text of new 251.1 as follows:]

Postcards and postal cards consist of single cards sent without a wrapper or envelope. Folded (double) cards must be mailed in envelopes at the First-Class Mail International rate of postage.

[Renumber 251.13 as 251.12 and 251.14 as 251.13.]

* * * * *

[Delete 251.2 and 251.3 in their entireties.]

[Revise the title of 252 as follows:]

252 Postage Rates and Fees

[Revise 252 by deleting reference to Aerogrammes as follows:]

Postcards and Postal Cards

Canada and Mexico $0.69

Marshall Islands and Micronesia $0.52

All other countries $0.90

* * * * *

[Revise the title and text of 253.2 as follows (deleting the titles and texts of 253.21 and 253.22):]

253.2 Dimensions

Each card claimed at a card rate must be:

a. Rectangular.

b. Not less than 3½ inches high, 5½ inches long, and 0.007 inch thick.

c. Not more than 4¼ inches high, 6 inches long and 0.016 inch thick.

Note: See 243.23 for larger cards.

[Revise the title of 254 as follows:]

254 Elements on the Face of a Mailpiece

* * * * *

[Revise the title of 254.2 as follows:]

254.2 Marking

* * * * *

[Delete the current 254.3 in its entirety. Renumber current 254.22 new 254.23 as 254.3 and 254.4.]

[Renumber current 251.15 and 251.16 as new 254.5 and 254.6.]

* * * * *

260 Direct Sacks of Printed Matter to One Addressee (M-Bags)

[Revise the title of 261 as follows:]

261 Description

[Revise the title of 261.1 as follows:]

261.1 General

[Revise 261.1 by changing the five bullets to items a through e and by revising item e as follows:]

* * * * *

e. Extra services: Certificate of mailing is available. Registry and insurance are not available.

[Revise the title of 261.2 as follows:]

261.2 Eligibility

* * * * *

261.22 Merchandise

* * * * *

[Revise the title of 262 as follows:]

262 Postage Rates and Fees

[Delete the title of 262.1. Renumber current 262.11 as new 262.1.and revise as follows:'']

262.1 M-bags

M-bags that are paid for at the First-Class Mail International rate of postage may contain any type of allowable printed matter or merchandise items (see 261). See the Individual Country Listings for the minimum bag charge for weights up to 11 pounds and the per-pound rate for each additional pound or fraction of a pound over 11 pounds.

[Delete 262.12.]

[Delete the title of 262.2. Renumber current 262.13 as new 262.2.]

[Renumber current 262.21 and 262.22 as new 262.3 and 262.4.]

[Revise the title of new 262.4 as follows:]

262.4 Stamps, Postage Evidencing Systems, PVI Labels, or Permit Imprint

* * * * *

[Revise item a as follows:]

a. By affixing postage stamps, meter stamps, PC postage, or a postage validation imprinter (PVI) label to PS Tag 158, M-bag Addressee Tag.

[Revise item b by removing the note.]

* * * * *

263.1 Weight Limits

[Revise the text in 263.1 as follows:]

There is no minimum weight requirement for the entry of M-bags or International Surface Air Lift (ISAL) M-bags. The maximum weight limit for M-bags is 66 pounds, which includes the tare weight of the sack.

Note: Customers who tender M-bags that weigh less than 11 pounds are required to pay the minimum ''11-pound bag charge'' that is applicable to the country of destination where the sack and its contents are to be delivered.

* * * * *

264.3 Customs Forms Required

[Revise 264.3 to read as follows]

M-bags that contain potentially dutiable printed matter or any category of printed matter that is combined with allowable merchandise items (see 261.22) must be accompanied by a fully completed PS Form 2976 or 2976–S, depending on value, which is to be fixed to PS Tag 158, M-bad Addressee Tag.

[Add new 265 as follows:]

265 Extra Services

Certificate of mailing is available. Return receipts, restricted delivery, registry service and insurance are not available with M-bags.

[Revise the title of 270 as follows:]

270 Free Matter for the Blind or Other Physically Handicapped Persons

271 Description

[Add new 271.1 as follows:]

271.1 General

Subject to the standards below and DMM 703, matter may be entered free of postage if mailed by or for the use of blind or other persons who cannot read or use conventionally printed materials due to a physical handicap.

[Add new 271.2 as follows:]

271.2 Eligibility

Eligible participants must be residents of the United States, including the several states, territories, insular possessions, and the District of Columbia, or American citizens domiciled abroad.

[Add new 271.3 as follows:]

271.3 Matter Sent To or by Blind or Other Physically Handicapped Persons

Acceptable matter and the conditions for mailing such matter that may be sent free under this standard are limited to the items described in 271 and DMM 703.

[Revise the title and text in 272 as follows:]

272 Postage Rates

The postage rate for an eligible item mailed as matter for the blind is:

a. Free when sent as First-Class Mail International.

b. The applicable rate based on the weight of the mailpiece if any level of service other than First-Class Mail International is desired.

* * * * *

274.2 Marking

[Revise 274.2 as follows (deleting the titles and text for 274.21 and 274.22:]

First-Class Mail International accepted as free matter must be marked ''Free Matter for the Blind or Handicapped'' in the upper right-hand corner of the address side of the mailpiece.

[Add new 275 as follows:]

275 Extra Services

Registered Mail and Insurance are the only extra services that can be added to mail sent as free matter for the blind or handicapped.

* * * * *

[Reserve 280.]

* * * * *

290 Commercial Services

291 (Reserved)

292 International Priority Airmail Service

[Change ''letter-post'' to ''First-Class Mail International'' throughout 292. Change PS Form 3652 to PS Form 3700 throughout 292.]

292.1 Description

* * * * *

292.12 Qualifying Mail

[Revise the first sentence as follows:]

Any item of the First-Class Mail International classification, as defined in 141.5, qualifies, including postcards.* * *

* * * * *

292.14 Dutiable Items

[Revise 292.14 by changing ''Parcel post (CP)'' to ''Priority Mail International.'']

* * * * *

[Revise the heading of 292.16 as follows:]

292.16 Extra Services Not Available

* * * * *

[Revise Exhibit 292.211 and add new Exhibit 292.211a and 292.211b as follows:]

Exhibit 292.211

International Priority Airmail (IPA) Rates

INTERNATIONAL PRIORITY AIRMAIL

Rate groups	Per piece	Full service per lb.	ISC drop shipment per lb.
1	$0.33	$4.55	$3.55
2	0.15	6.10	5.10
3	0.32	7.50	6.50
4	0.32	7.70	6.70
5	0.15	6.50	5.50
6	0.15	5.80	4.80
7	0.15	7.50	6.50
8	0.12	8.00	7.00
9	0.27	8.25	7.25
Worldwide	0.25	8.50	7.50

Exhibit 292.211a

INTERNATIONAL PRIORITY AIRMAIL (IPA) M-BAG—FULL SERVICE

Rate groups	Full service per lb.
1	$2.10
2	2.70
3	3.60
4	5.15
5	4.40
6	4.20
7	4.95
8	4.85
9	5.60

Note: M-bags are subject to the minimum rate for 11 pounds.

Exhibit 292.211b

INTERNATIONAL PRIORITY AIR MAIL (IPA) M-BAG-ISC DROP SHIPMENT

Weight not over (lb.)	Rate groups								
	1	2	3	4	5	6	7	8	9
5	$19.30	$25.00	$30.85	$44.50	$38.75	$38.65	$44.80	$42.50	$47.75
6	19.75	25.60	31.85	46.25	39.90	39.45	45.95	43.85	49.60
7	20.20	26.20	32.85	48.00	41.05	40.25	47.10	45.20	51.45
8	20.65	26.80	33.85	49.75	42.20	41.05	48.25	46.55	53.30
9	21.10	27.40	34.85	51.50	43.35	41.85	49.40	47.90	55.15
10	21.55	28.00	35.85	53.25	44.50	42.65	50.55	49.25	57.00
11	22.00	28.60	36.85	55.00	45.65	43.45	51.70	50.60	58.85
Each additional pound or fraction of a pound	2.00	2.60	3.35	5.00	4.15	3.95	4.70	4.60	5.35

* * * * *

292.223 Permit Imprint

[Revise the text of 292.223 by changing the reference to Exhibit 152.3 to 152.34.]

* * * * *

[Revise Exhibit 292.442 by changing the Australia rate group assignment to rate group 9.]

293 International Surface Air Lift (ISAL) Service

[Change ''letter-post'' to ''First-Class Mail International'' throughout 293. Change PS Form 3650 and 3655 to PS Form 3700.]

293.1 Definition

[Revise the second sentence to read as follows:]

* * *The cost is lower than First-Class Mail International.* * *

* * * * *

[Revise the heading of 293.4 as follows:]

293.4 Extra Services

* * * * *

[Revise 293.71 as follows:]

293.71 Rates

INTERNATIONAL SURFACE AIR LIFT (ISAL)

Rate groups	Per piece	Full service per lb.	Direct shipment per lb.	ISC drop shipment per lb.
1	$0.32	$3.20	$2.70	$2.20
2	0.15	5.15	4.65	4.15
3	0.30	4.00	3.50	3.00
4	0.32	4.35	3.85	3.35
5	0.15	5.45	4.95	4.45
6	0.15	5.55	5.05	4.55
7	0.15	5.45	4.95	4.45
8	0.12	6.60	6.10	5.60
9	0.22	4.45	3.95	3.45

INTERNATIONAL SURFACE AIR LIFT (ISAL) M-BAG-FULL SERVICE AND DIRECT SHIPMENT

Rate groups	Full service per lb.	Direct shipment per lb.
1	$1.60	$1.60
2	1.70	1.70
3	2.00	2.00

INTERNATIONAL SURFACE AIR LIFT (ISAL) M-BAG-FULL SERVICE AND DIRECT SHIPMENT—Continued

Rate groups	Full service per lb.	Direct shipment per lb.
4	2.80	2.80
5	2.35	2.35
6	2.35	2.35
7	2.60	2.60
8	3.25	3.25
9	3.00	3.00

Note: M-bags are subject to the minimum rate for 11 pounds.

INTERNATIONAL SURFACE AIR LIFT M–BAG—ISC DROP SHIPMENT

Weight not over (lb.)	Rate groups								
	1	2	3	4	5	6	7	8	9
5	$15.90	$14.30	$11.45	$16.25	$12.90	$14.40	$12.05	$16.20	$18.25
6	16.00	14.85	12.75	18.40	14.60	15.85	14.35	19.00	20.25
7	16.10	15.40	14.05	20.55	16.30	17.30	16.65	21.80	22.25
8	16.20	15.95	15.35	22.70	18.00	18.75	18.95	24.60	24.25
9	16.30	16.50	16.65	24.85	19.70	20.20	21.25	27.40	26.25
10	16.40	17.05	17.95	27.00	21.40	21.65	23.55	30.20	28.25
11	16.50	17.60	19.25	29.15	23.10	23.10	25.85	33.00	30.25
Each additional pound or fraction of a pound	1.50	1.60	1.75	2.65	2.10	2.10	2.35	3.00	2.75

[Revise Exhibit 293.71 by changing the rate group assignment for Australia to rate group 9.]

* * * * *

293.752 Piece Rate

[Revise the text of 293.752 by changing the reference to Exhibit 152.3 to 152.34.]

* * * * *

293.9 Preparation Requirements

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[Delete 293.92. Renumber 293.93, 293.94, and 293.95 as 293.92, 293.93, and 293.94.]

* * * * *

[Delete the text in 294 to eliminate Publishers' Periodicals service. Publishers' Periodicals service is discontinued:]

294 (Reserved)

* * * * *

[Delete the text in 295 to eliminate Books and Sheet Music service. Books and Sheet Music service is discontinued:]

295 (Reserved)

* * * * *

297 International Customized Mail

[Change ''letter-post'' to ''First-Class Mail International'' and change ''Global Priority Mail'' to ''Priority Mail International'' throughout 297.]

* * * * *

[Revise the heading of 3 as follows:]

3 Extra Services

310 Certificate of Mailing

* * * * *

312 Availability

[Revise 312 by deleting the words ''letter-post,'' ''parcel post'' and ''recorded delivery'' as follows:]

Customers can purchase a certificate of mailing when they send unregistered First-Class Mail International, post/postal cards, free matter for the blind and uninsured Priority Mail International parcels. To obtain an additional certificate after mailing, the mailer must present the original certificate and an additional certificate endorsed ''Duplicate'' or a copy showing the original dates of mailing. The additional certificate must be postmarked to show the current date. A certificate of mailing cannot be obtained in combination with registered mail, insured parcels, or bulk mailings of 200 pieces or more that bear a permit imprint.

313 Fees

313.1 Individual Pieces

[*Revise 313.1 by changing ''letter-post'' to ''First-Class Mail International'' and ''parcel post'' to ''Priority Mail International''.*]

The fee for certificates of mailing for ordinary First-Class Mail International items and ordinary Priority Mail International parcels is $1.05 for pieces listed individually on PS Form 3817, Certificate of Mailing. The fee for three or more pieces individually listed on PS Form 3877, Firm Mailing Book, or an approved customer-provided manifest, is $0.35 per piece. Each additional copy of PS Form 3817 or firm mailing bills is available for $1.05.

313.2 Bulk Pieces

[*Revise 313.2 by changing ''letter-post'' to ''First-Class Mail International''.*]

PS Form 3606, Certificate of Bulk Mailing, is used to specify the total number of identical pieces of ordinary First-Class Mail International that are paid for with regular postage stamps, precanceled stamps, or meter stamps. The following certificate of mailing fees apply:

Up to 1,000 pieces	$5.50
Each additional 1,000 pieces or fraction	$0.60
Duplicate copy	$1.05

* * * * *

320 Insurance

321 Description

[*Revise 321 as follows:*]

Insurance is provided against loss, damage, or rifling for Priority Mail International parcels. Compensation varies according to the fee paid. For parcels delivered to the addressee in damaged condition or with missing contents, payment is made to the addressee unless the addressee waives payment, in writing, in favor of the sender.

322 Availability

[*Revise 322 as follows:*]

Insurance is available only for Priority Mail International parcels and only to certain countries. See Individual Country Listings. Insurance is not available for the Priority Mail International Flat-Rate envelope.

* * * * *

324 Processing Requests

324.1 Mailing Receipt and Insurance Number

[*Revise 324.11 as follows:*]

324.11 General Use

All Priority Mail International parcels must be numbered. Form 2976–A, Customs Declaration and Dispatch Note—CP 72, and the cash register receipt issued at the time of mailing will serve as proof of mailing and proof of insurance. Volume mailers may use PS Form 3877, Firm Mailing Book for Accountable Mail, as the sender's receipt.

* * * * *

[*Revise 324.12 as follows:*]

324.12 Accepting Clerk's Responsibility

Accepting clerk must:

a. Indicate on Form 2976–A the amount for which the parcel is insured. Write the amount in U.S. dollars in ink in the ''Insured Amount (US) block.''

b. Convert the U.S. dollar amount to the special drawing right (SDR) value and enter it in the SDR value block. For example:

INSURED VALUE
$100.00 (U.S.)
68.60 SDR

c. See Exhibit 324.12 for a table showing the conversion of U.S. dollar values up to $600 to SDR equivalents. To determine SDR equivalents above $600, multiply the insured amount, rounded up to the next full dollar, by the conversion factor of 0.6860.

Note: Use the following rates when converting between U.S. dollars and special drawing right (SDR values): $1 U.S. = 0.6860 SDR 1 SDR = $1.46 U.S. ($1.4577 U.S.)

d. Write a bold capital V in the space provided for the insured number as an indicator that additional insurance was purchased.

e. Indicate special contents for fragile liquid and perishable items.

f. Round stamp Form 2976–A in the appropriate place on each copy.

* * * * *

324.2 Marking

324.21 Sender's Responsibility

[*Delete 324.22 in its entirety.*]

[*Renumber Exhibit 324.22 as Exhibit 324.12.*]

324.3 Postmarking

* * * * *

[*Revise 324.5 to read as follows:*]

324.5 Return Receipt

Return receipt service is available to many countries. See individual country listings.

* * * * *

[*Revise 325 as follows:*]

325 Indemnity Claims and Payments

The sender must submit the original mailing receipt, sender's copy of PS Form 2976–A, Customs Declaration and Dispatch Note—CP72}, as proof of mailing and proof of insurance to file a claim. (See Chapter 9)

* * * * *

330 Registered Mail

331 Description

[*Revise 331 by deleting the words ''and do not extend uniformly to damage or rifling of contents.''*]

332 Availability

[*Revise the text to read as follows:*]

Customers can purchase registered mail service when they send Priority Mail International flat-rate envelope or First-Class Mail International items, post/postal cards, and free matter for the blind items. Registered items may weigh up to 4 pounds. Registered Mail Service is not available in combination with Priority Mail International parcels, or M-bags to one addressee. See Individual Country Listings for country-specific prohibitions and restrictions.

333 Fees and Indemnity Limits

333.1 Registration Fees

[*Revise 333.1 to indicate the new registered fee as follows:*]

The registry fee for all countries is $10.15.

333.2 Indemnity Limit

[*Revise 333.2 to reflect the 2007 indemnity limit as follows:*]

Regardless of the declared value of a registered item, the maximum amount of indemnity payable for loss, damage, or rifling is $43.73.

334 Processing Requests

334.1 Mailing Receipt and Registration Number

* * * * *

334.12 Sender's Responsibility

[*Revise 334.12b as follows:*]

b. Declare the full value of mail presented for registration. The value declared must be identical to the value stated on Form 2976, Customs Declaration CN22—Sender's Declaration. Items on which identical values are not declared will be refused. (See IMM 123.711)

[*Revise item c as follows:*]

* * * * *

c. The sender should retain the receipt and must submit it if he or she wishes to file a claim for the registered item (see Chapter 9).

[*Revise 334.13 by adding new a and re-lettering current a through d as b through e as follows:*]

334.13 Accepting Clerk's Responsibility

Accepting clerk must:

a. Verify that the value declared on Form 3806 and the value declared on Form 2976 are identical. Refuse items on which the declared values are not the same.

* * * * *

334.14 Preparation

[*Revise 334.14 as follows:*]

Items bearing an address in pencil or any other erasable format must not be accepted for registered mail service.

* * * * *

334.4 Sealing

334.41 Sender's Responsibility

[*Revise the first sentence of 334.41 as follows:*]

Senders must securely seal all items presented for registration.

* * * * *

[*Revise title of 334.42 as follows:*]

334.42 Registered Free Matter for the Blind or Other Physically Handicapped Persons

* * * * *

336 Preparation

[Delete 336 in its entirety.]

340 Return Receipt

341 Description

[Revise 341 as follows:]

PS Form 2865, Return Receipt for International Mail (Avis de Reception), is a pink card that is attached to a registered item, an insured parcel, or an Express Mail International item to certain countries (see 221.4), at the time of mailing, and which is removed and signed at the point of delivery and returned to the sender. Return Receipt service provides the sender with evidence of delivery. Return receipts are completed in the country of destination in accordance with its internal regulations, which may not require the addressee's signature except under

special circumstances. These receipts are returned to the sender by airmail.

342 Availability

[Revise 342 by deleting the words ''recorded delivery'' to read as follows:]

Return receipts can be purchased only at the time of mailing and are available only for registered items and insured parcels. Return receipts are also available to a limited number of countries for Express Mail International (see 221.4). Some countries do not admit return receipts or restrict them to registered mail. See Individual Country Listings.

343 Fee

[Revise 343 to reflect that fee is linked to domestic case as follows:]

The fee for a return receipt is $2.15. This fee must be paid in addition to postage and other applicable charges. Return receipt service is available at no charge for Express Mail International to certain countries.

Note: Include the weight of the return receipt when determining the postage for mailing the item.

344 Processing Requests

344.1 Form

344.11 Sender's Responsibility

[Revise 344.11 as follows:]

Sender must enter the return address on the return receipt.

344.12 Accepting Clerk's Responsibility

[Revise 344.12 as follows:]

Accepting clerk must:

a. Record the return receipt fee on the insured or registered mailing receipt.

b. Enter the address of the addressee on the return receipt.

c. Attach the return receipt to the item.

d. Affix and cancel postage equal to the sum of the return receipt fee, postage, and other applicable fees.

* * * * *

[Delete 344.3 in its entirety.]

* * * * *

[Renumber 344.4 as 344.3 and revise text as follows:]

344.3 Return Receipt Improperly Completed or Not Received

If the sender does not receive a return receipt for which a fee was paid, or if the sender receives an improperly completed return receipt, an inquiry may be filed. (See 920 for inquiry procedures.)

350 Restricted Delivery

* * * * *

352 Availability

* * * * *

[Revise item b by deleting ''recorded delivery'' as follows:]

b. For registered items.

* * * * *

353 Fee

[Revise 353 as follows:]

Fee is $4.10 * * *

[Delete current 360, Recorded Delivery, in its entirety. Reserve 360.]

* * * * *

370 Supplemental Services

* * * * *

371 International Money Orders

371.1 Description

371.11 General

[Revise 371.11 by changing ''Global Express Mail Service (EMS)'' to ''Express Mail International.'']

* * * * *

371.3 Fees

[Revise 371.3 as follows:]

The fee for money orders payable in countries that accept Form MP1 is $3.85 per money order.

372 International Reply Coupons

* * * * *

372.3 Selling Price and Rate of Exchange

[Revise the first sentence in item a as follows:]

a. The selling price of a reply coupon in the United States is $2.00 * * *

[Revise item b by deleting ''(including aerogrammes)'' and by changing the rate to $0.90 per coupon.]

* * * * *

373 International Business Reply Service

* * * * *

373.4 Fees

[Revise 373.4 as follows:]

a. Envelopes up to 2 ounces: $1.40.

b. Cards: $0.90.

4 Treatment of Outbound Mail

* * * * *

420 Shortpaid and Unpaid Mail

[Change ''letter-post'' to ''First-Class Mail International'' and ''Global Express Mail'' to ''Express Mail International'' throughout 420.]

* * * * *

[Delete current 442, Recorded Delivery, in its entirety.]

5 Nonpostal Export Regulations

[Change ''letter-post'' to ''First-Class Mail International'' and ''parcel post'' to ''Priority Mail International'' throughout 5.]

* * * * *

550 Dried Whole Eggs

* * * * *

552 Charges

[Revise the first sentence of 552 as follows:]

A charge of $1.05 * * *

* * * * *

560 Tobacco Seeds and Tobacco Plants

* * * * *

562 Charges

[Revise the first sentence of 562 as follows:]

A charge of $1.05 * * *

6 Special Programs

610 Postal Qualified Wholesaler Program

* * * * *

613 Qualifying as a Wholesaler

613.1 Letter of Request

* * * * *

[Revise the address in 613.1 as follows:]

Executive Director, Global Business Management, U.S. Postal Service, 475 L'Enfant Plz., SW., Rm 4011, Washington, DC 20260–4011.

* * * * *

7 Treatment of Inbound Mail

* * * * *

712 Customs Clearance and Delivery Fees

* * * * *

712.3 Amount of Postal Service Fee

[Revise the text of 712.3 by changing the fee from $4.75 to $5.35.]

* * * * *

730 Shortpaid Mail to the United States

731 Computation of Postage Due

[Revise the handling charge in the example to correspond with the text in 731b. Center T and x within equation as in current IMM as follows:]

b. The receiving exchange office in the United States multiplies the T fraction by the U.S. international letter rate to determine the short paid amount in U.S. currency. This amount, plus a $0.50 handling charge, accounts for the postage-due amount to be collected on delivery. The postage-due formula is:

$$T \; shortpaid\ amount \times \text{First-Class Mail International rate}$$

International letter rate of postage to U.S.
* * * +$0.50 handling charge * * *
= Postage due amount
* * * * *

[Revise the title of 750 as follows:]

750 Extra Services

754 Restricted Delivery

754.1 Inbound Registered Mail

[Revise 754.1 as follows:]

Inbound registered mail, accompanied by a return receipt and bearing the notation *A Remettre en Main Propre or Restricted Delivery,* should be delivered only to the addressee or their authorized agent.

* * * * *

[Delete 755, Recorded Delivery, in its entirety.]

760 Forwarding

762.2 Undeliverable Domestic Mail Bearing U.S. Postage and a Foreign Return Address

* * * * *

[Revise the text of item 762.2 c as follows:]

* * * * *

c. First-Class Mail containing merchandise, Standard Mail items, or Package Services parcels, which bear a foreign return address, must be held at the Post Office of the addressee, while a request for instructions is sent to International Claims, St. Louis ASC, P.O. Box 80146, St. Louis, MO 63180–0146: Requests must include the following information:

(1) Names and addresses of sender and addressee.

(2) Weight of the item and any special services.

(3) Nature and value of contents if known. The International Claims Office will contact the sender for disposition instructions, completion of the required customs forms, and payment of additional postage.

* * * * *

764 Mail of Foreign Origin

* * * * *

764.2 Forwarding to another Country

* * * * *

764.23 Parcels

* * * * *

[Add new 764.232 as follows:]

[Renumber current 764.232 as new 764.233.]

764.232 Delivery to an Alternate Addressee

If the addressee has moved to a third country or if the sender has included instructions for delivery to an alternate addressee in a third country, the Post Office facility must hold the parcel and request instructions from International Claims, St. Louis ASC, P.O. Box 80146, St. Louis, MO 63180–0146. Requests should include the following information:

a. Names and addresses of sender and addressee, or alternate addressee.

b. Weight of the parcel.

c. Whether the parcel is insured.

d. Nature and value of the contents as shown on the customs declaration.

* * * * *

766 Retention Period

766.1 General Procedure

[Revise the text of 766.1 by changing the Domestic Mail Manual reference from D042.1.7 to 508.1.1.7.]

770 Undeliverable Mail

771 Mail of Domestic Origin

* * * * *

[Revise the title of 771.5 as follows:]

771.5 Return Charges for First-Class Mail International

771.51 General Procedure

* * * * *

[Revise 771.51 by changing ''letter-post'' to ''First-Class Mail International.'']

[Revise item a as follows.]

a. First-Class Mail International.

* * * * *

[Revise item d as follows:]

d. First-Class Mail International M-bag.

* * * * *

[Delete items e, f, and g.]

771.52 Exceptions

[Revise items a and b by changing ''letter post'' to ''First-Class Mail International.'']

[Revise the title of 771.6 as follows:]

771.6 Return Charges for Priority Mail International

* * * * *

771.7 Handling of Returned Parcels

771.71 Refused by Sender

[Revise 771.71 by changing ''parcel post'' to ''Priority Mail International.'']

* * * * *

[Add new 771.73 as follows:]

771.73 Sender Has Moved to Another Country

If the sender has moved to another country, the Post Office facility must hold the parcel and request instructions from International Claims, St. Louis ASC, P.O. Box 80146, St. Louis, MO 63180–0146. Requests should include the following information:

a. New address of the sender.

b. Amount of return charges due on the parcel.

c. Weight of the parcel.

d. Whether the parcel is insured.

e. Nature and value of the contents as shown on the customs declaration.

* * * * *

780 Items Mailed Abroad by or on Behalf of Senders in the United States

* * * * *

783 Advance Payment Required

783.1 Sample Mailpiece

[Revise 783.1 to change room number and plus for code in address to 5726.]

* * * * *

9 Inquiries, Indemnities, and Refunds

* * * * *

920 Inquiries and Claims

921 Inquiries

* * * * *

921.2 Initiating an Inquiry

[Revise the first two sentences in 921.2 as follows:]

Inquiries can be initiated for Global Express Guaranteed (GXG) items, Express Mail International items, registered items, and insured and ordinary parcels. Inquiries are not accepted for ordinary letters, Priority Mail International flat-rate envelope items, or M-bags.* * *

Exhibit 921.2

Time Limits for Inquiries

[Revise the product or Extra Services column and the note in Exhibit 921.2 as follows:]

Product	Who	When (from mailing date)	
		No sooner than	No later than
Global Express Guaranteed	U.S. Sender Only	3 days	30 days

Product	Who	When (from mailing date)	
		No sooner than	No later than
Express Mail International	U.S. Sender Only	3 days	90 days
Express Mail International with Guarantee Service	U.S. Sender Only	3 days	30 days
Registered items, insured or ordinary parcels	Sender or Addressee	7 days	6 months

*Inquires are not accepted on ordinary letters, Priority Mail International flat-rate envelopes or M-bags.

921.3 How To Initiate

[Revise the text and change item d as follows:]

Customers must call the International Inquiry Center at 800–222–1811 within the time limits listed in Exhibit 921.2 to initiate an inquiry. Customers will be asked to provide information regarding the mailing, including, but not limited to the following:

a. Mailing receipt number or barcode number of the article.

b. Names and addresses of the mailer and the addressee.

c. Date of mailing.

d. Description of contents.

921.4 Inquiry Process

[Revise the text of 921.4 as follows:]

After the Postal Service customer provides the International Inquiry Center with the relevant mailing information, the International Inquiry Center will correspond with the appropriate foreign post and advise the customer of the results of the inquiry. Customers must allow foreign posts approximately 60 days to research and respond to the International Inquiry Center for inquiries on registered items, and insured and ordinary parcels. When there is a determination that an item has been lost, the International Inquiry Center will mail a claim packet to the customer. The packet will include a letter of instruction on how to complete and submit the claim.

921.5 General Procedures

921.51 Nondelivery

[Revise the text of 921.51 as follows:]

The U.S. Postal Service will initiate an inquiry within the time frames specified in 921.2 with the destination postal administration in any case involving a GXG, Express Mail International, registered item, or insured or ordinary parcel that has not been delivered. Inquiries are not accepted for Priority Mail International flat-rate items, ordinary letters, or M-bags.

921.52 Return Receipts Improperly Completed or Not Received

[Revise the text of 921.52 to read as follows:]

If the sender receives an improperly completed return receipt (see 341 for completion at destination) or a return receipt is not received, the sender may go to any Post Office and request a refund of the return receipt special service fee. If the sender wants to inquire about the delivery of the article, the sender must call 800–222–1811 to initiate an inquiry (see 921.1).

921.53 Rifled Parcels

[Revise title and text of 921.53 as follows:]

921.53 Damaged or Rifled Parcels, Registered Mail, and Express Mail International

Customers must go to a Post Office to report instances of damaged or rifled items. Postal personnel should complete PS Form 673, *Report of Rifled Parcel,* in accordance with POM 169.3 or Form 2856, *Damage Report of Insured Parcel and Contents,* in accordance with POM 146.112 for international and/or domestic articles as applicable.

* * * * *

922 Claims

922.1 General Description

[Revise the first sentence in 922.1 as follows:]

A claim is a request by a U. S. Postal Service customer for an indemnity payment that resulted in the loss, damage, or rifling of a GXG, Express Mail International, registered item, or insured or ordinary parcel. See 221.3, 237, 320, 330, and country listings for information on indemnity limits.* * *

922.2 Filing a Claim

[Revise 922.2 as follows:]

Claims may be filed for GXG, Express Mail International, registered items, and insured and ordinary parcels as noted in Exhibit 922.2. Claims may not be filed for ordinary letters or M-bags. Claims for registered items, and insured and ordinary parcels may not be filed until after an inquiry has been completed in accordance with the procedures in 921. Claims for rifled or damaged articles should be filed immediately. Claims for registered items, insured, and ordinary parcels delivered to the addressee in damaged condition or with missing contents are payable only to the addressee, unless the addressee waives their right to payment, in writing, in favor of the sender. All claims for inbound international registered items and insured and ordinary parcels received in damaged condition or with missing contents must be supported by Form 2856. If the addressee does not accept delivery and the item is returned to the sender, the sender will be the payee.

Filing Claims

[Revise the Product and Who column and the note in Exhibit 922.2 as follows:]

Product	Who	Lost article	How damaged/rifled
GXG and Express Mail International	U.S. Sender Only	800–222–1811	1–800–222–1811.
GXG and Express Mail International (article returned to sender)	U.S. Sender Only	N/A	Any Post Office* (PS Form 2855).
Registered item, insured parcel, ordinary parcel	U.S. Sender or Addressee.	800–222–1811	Any Post Office* (PS Form 2855).

*Must present the article, mailing container, wrapping, packaging, and any other contents received in damaged condition or with missing contents to a post office immediately.

* * * * *

922.3 Claims Process

* * * * *

922.31 Proof of Mailing

* * * * *

[Revise text of 922.31 and items a (2), (3), and (4) to read as follows:]

Indemnity claims for GXG, Express Mail International, registered mail, and insured and ordinary parcels must be supported as follows:

a. If mailed in the United States:

(1) For Global Express Guaranteed items, the original receipt of the GXG Air Waybill/Shipping Invoice.

(2) For Express Mail International items, PS Form 2861, Express Mail International Service Inquiry, received from the International Inquiry Center.

(3) For registered items and insured parcels, the original mailing receipt and sender's copy of PS Form 2976–A, Customs Declaration and Dispatch Note, CP 72 issued at the time of mailing. Copies are not acceptable.

(4) For ordinary parcels, the customer copy of PS Form 2976–A, Customs Declaration and Dispatch Note—CP 72.

[Add a new note after item b as follows:]

b. If mailed from a foreign country: The original mailing receipt if available, the customs label, the wrapper, and any other markings or endorsements on the mailing container that indicate how it was sent.

Note: Mailing particulars must also be verified with the country of origin before a claim can be settled.

* * * * *

922.4 Processing Claims for Rifled or Damaged Articles

* * * * *

922.42 Postal Service

* * * * *

[Revise the text of 922.42b and delete the last sentence ''There is no fee for processing a claim.'' to read as follows.]

Postal Service personnel must:

a. Complete sections III and IV of PS Form 2855.

b. Prepare a damage report on Form 2856, *Damage Report of Insured Parcel and Contents,* detailing the condition of the item at the time of delivery, and indicate whether or not the item was properly packaged to withstand normal handling in international mail.

c. Attach the damage report and the documentation described in 922.3 to the claim.

d. Send PS Form 2855 and related documents, including the customs label and the wrapper, if appropriate, to: International Claims, St. Louis ASC, PO Box 80146, St. Louis, MO 63180–0146.

* * * * *

923 Disposition of Damaged Mail

[Revise the introductory sentence of 923 and item b to read as follows:]

Dispose of damaged registered mail, insured parcels, and ordinary parcels for which claims have been filed as follows:

* * * * *

b. International insured parcels, ordinary parcels, and Canadian registered mail:

* * * * *

930 Indemnity Payments

931 Adjudication and Approval

* * * * *

931.2 International Claims

[*Revise title and text of 931.21 by changing ''Parcel Post'' to ''Parcels'', and text as follows:*]

931.21 Indemnity Claims for International Registered Mail, Insured Parcels, and Ordinary Parcels of U.S. and Foreign Origin

Indemnity Claims relating to international registered mail, insured and ordinary parcels of both U.S. and foreign origin are adjudicated by the St. Louis Accounting Service Center.

931.22 Country of Origin Pays Indemnity

[*Revise 931.22 as follows:*]

Payment is made as follows:

a. Express Mail claims are paid by the country of origin to the sender. Payments to U.S. senders will by made by the U.S. Postal Service.

b. Indemnity for the loss of registered mail, insured parcels and ordinary parcels is paid by the country of origin to the sender. Payments to U.S. senders will be made by the U.S. Postal Service. The sender may waive their right to payment, in writing, in favor of the addressee. Payment in such cases will be made by the destination administration.

c. Claims for items delivered in damaged condition or with missing contents may be made to the addressee by the destination administration. If the addressee waives their right to payment, in writing, in favor of the U.S. sender, payment will be made to the sender by the U.S. Postal Service.

d. Claims for items mailed in foreign administrations that are delivered in damaged condition or with missing contents may be paid to the addressee. Payments will be made to the U.S. addressee by the U.S. Postal Service. The addressee may waive their right to payment in favor of the sender. Payment in such cases will be made by the origin administration.

* * * * *

[*Revise title of 932 as follows:*]

932 General Exceptions To Payment—Registered Mail, Priority Mail International Insured Parcels, and Priority Mail International Ordinary Parcels

* * * * *

[*Revise title of 933 by changing ''Parcel Post'' to ''Parcels.''*]

933 Payments for Priority Mail International Insured Parcels and Priority Mail International Ordinary Parcels

933.1 General Provisions

[*Revise title and text of 933.11 as follows:*]

933.11 Insured Parcels

Indemnity may be paid for loss, rifling, or damage, based on the actual value of articles at the time and place of mailing.

933.12 Indemnity Will Not Be Paid

[*Revise third sentence of item d(3) to read as follows:*]

In addition to the general exceptions to payment described in 932, indemnity will not be paid:

d. For parcels that:

(3) Were not posted in the manner prescribed. In the event of loss, rifling, or damage of mail erroneously accepted for insurance to other countries, limited indemnity may be paid as if it had been addressed to a domestic destination, *i.e.* on the basis of the indemnity limits for domestic insured mail. If postage was erroneously collected at other than a parcel rate, but the parcel was otherwise properly accepted for insurance, indemnity may be paid pursuant to the general provisions of this section and the special provisions of 933.2.

* * * * *

[*Revise titles of 933.13 and 933.14 by changing ''Parcel Post'' to ''Parcels.''*]

933.13 Ordinary Priority Mail International Parcels—Indemnity Limitations

* * * * *

933.14 Ordinary Priority Mail International Parcels—Exceptions to Indemnity

* * * * *

934 Payments for Registered Mail

934.1 General Provisions

* * * * *

[*Revise title and text of 934.12 as follows:*]

934.12 Parcels Erroneously Accepted as Registered Mail

If a parcel is accepted in error as registered mail, indemnity may be paid under the conditions in 934.2.

934.13 Indemnity Will Not Be Paid

* * * * *

[*Revise item b to read as follows:*]

b. To anyone in the United States, other than the addressee, for items delivered in damaged condition or with missing contents. The addressee may waive payment, in writing, in favor of the sender.

* * * * *

934.2 Special Provisions

[*Revise amount payable in 934.2 to ''$43.73.''*]

* * * * *

[*Revise 935 by changing ''Global Express Mail'' and ''Global Express Mail (EMS)'' to ''Express Mail International'' throughout.*]

* * * * *

940 Postage Refunds

[*Revise 941 by changing ''letter-post'' and ''parcel post'' to ''First-Class Mail International'' and Priority Mail International'' throughout.*]

* * * * *

[*Revise 942 by changing ''Global Express Mail'' and ''EMS'' to ''Express Mail International'' throughout.*]

* * * * *

942 Postage Refunds for Express Mail International Items

* * * * *

942.5 Unallowable Refund—Express Mail International with No Service Guarantee

* * * * *

942.53 Consequential Damages

[*Add new last sentence to 942.53 as follows:*]

See DMM 609 and 503, and IMM 221.3 and 935.2 for limitations of indemnity coverage.

943 Processing Refund Applications

943.1 Items Originating in the United States

[*Revise first sentence 943.1 as follows:*]

Requests for refunds for ordinary letters, registered mail, Priority Mail International, Express Mail International, and Express Mail International with Guarantee service originating in the United States are handled as follows:* * *

[*Revise item b by deleting ''Recorded Delivery'' and changing ''parcel post'' to ''parcel.''*]

[*Revise item c by changing ''EMS'' to ''Express Mail International.''*]

* * * * *

Neva R. Watson,

Attorney, Legislative.

[FR Doc. E7–6048 Filed 4–3–07; 8:45 am]

BILLING CODE 7710–12–P

Federal Register

Wednesday,
April 4, 2007

Part IV

Environmental Protection Agency

40 CFR Part 63

National Emission Standards for Hazardous Air Pollutants for Area Sources: Acrylic and Modacrylic Fibers Production, Carbon Black Production, Chemical Manufacturing: Chromium Compounds, Flexible Polyurethane Foam Production and Fabrication, Lead Acid Battery Manufacturing, and Wood Preserving; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA-HQ-OAR–2006–0897; FRL–8293–2]

RIN 2060-AN44

National Emission Standards for Hazardous Air Pollutants for Area Sources: Acrylic and Modacrylic Fibers Production, Carbon Black Production, Chemical Manufacturing: Chromium Compounds, Flexible Polyurethane Foam Production and Fabrication, Lead Acid Battery Manufacturing, and Wood Preserving

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing six national emissions standards for hazardous air pollutants for seven area source categories. The proposed emissions standards and associated requirements for two area source categories (Flexible Polyurethane Foam Production and Flexible Polyurethane Foam Fabrication) are combined in one subpart. The proposed emissions standards for new and existing sources are based on EPA's proposed determination as to what constitutes the generally available control technology or management practices for each area source category.

DATES: Comments must be received on or before May 4, 2007, unless a public hearing is requested by April 16, 2007. If a hearing is requested on the proposed rules, written comments must be received by May 21, 2007. Under the Paperwork Reduction Act, comments on the information collection provisions must be received by OMB on or before May 4, 2007.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2006–0897 by one of the following methods:

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *E-mail: a-and-r-docket@epa.gov.*
- *Fax:* (202) 566–1741.
- *Mail:* National Emission Standards for Hazardous Air Pollutants for Area Sources: Acrylic and Modacrylic Fibers Production, Carbon Black Production, Chemical Manufacturing: Chromium Compounds, Flexible Polyurethane Foam Production and Fabrication, Lead Acid Battery Manufacturing, and Wood Preserving Docket, Environmental Protection Agency, Mailcode: 6102T, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attn: Desk Officer for EPA, 725 17th St., NW., Washington, DC 20503.
- *Hand Delivery:* EPA Docket Center, Public Reading Room, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20460. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Note: The EPA Docket Center suffered damage due to flooding during the last week of June 2006. The Docket Center is continuing to operate. However, during the cleanup, there will be temporary changes to Docket Center telephone numbers, addresses, and hours of operation for people who wish to make hand deliveries or visit the Public Reading Room to view documents. Consult EPA's **Federal Register** notice at 71 FR 38147 (July 5, 2006) or the EPA Web site at *http://www.epa.gov/epahome/dockets.htm* for current information on docket operations, locations and telephone numbers.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2006–0897. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or e-mail. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *www.regulations.gov*, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the National Emission Standards for Hazardous Air Pollutants for Area Sources: Acrylic and Modacrylic Fibers Production, Carbon Black Production, Chemical Manufacturing: Chromium Compounds, Flexible Polyurethane Foam Production and Fabrication, Lead Acid Battery Manufacturing, and Wood Preserving Docket, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Sharon Nizich, Sector Policies and Programs Division, Office of Air Quality Planning and Standards (D243–02), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–2825; fax number: (919) 541–3207; e-mail address: *nizich.sharon@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by the proposed standards include:

Category	NAICS code [1]	Examples of regulated entities
Industry:		
Acrylic and modacrylic fibers production.	325222	Area source facilities that manufacture polymeric organic fibers using acrylonitrile as a primary monomer.

Category	NAICS code [1]	Examples of regulated entities
Carbon black production	325182	Area source facilities that manufacture carbon black using the furnace, thermal, or acetylene decomposition process.
Chemical manufacturing: chromium compounds.	325188	Area source facilities that produce chromium compounds, principally sodium dichromate, chromic acid, and chromic oxide, from chromite ore.
Flexible polyurethane foam production.	326150	Area source facilities that manufacture foam made from a polyurethane polymer.
Flexible polyurethane foam fabrication operations.	326150	Area source facilities that cut or bond flexible polyurethane foam pieces together or to other substrates.
Lead acid battery manufacturing	335911	Area source facilities that manufacture lead acid storage batteries made from lead alloy ingots and lead oxide.
Wood preserving	321114	Area source facilities that treat wood such as lumber, ties, poles, posts, or pilings with a preservative.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. To determine whether your facility would be regulated by this action, you should examine the applicability criteria in 40 CFR 63.11393 of subpart LLLLLL (NESHAP for Acrylic and Modacrylic Fibers Production Area Sources), 40 CFR 63.11400 of subpart MMMMMM (NESHAP for Carbon Black Production Area Sources), 40 CFR 63.11407 of subpart NNNNNN (NESHAP for Chemical Manufacturing Area Sources: Chromium Compounds), 40 CFR 63.11414 of subpart OOOOOO (NESHAP for Flexible Polyurethane Foam Production and Fabrication Area Sources), 40 CFR 63.11421 of subpart PPPPPP (NESHAP for Lead Acid Battery Manufacturing Area Sources), or 40 CFR 63.11428 of subpart QQQQQQ (NESHAP for Wood Preserving Area Sources). If you have any questions regarding the applicability of this action to a particular entity, consult either the air permit authority for the entity or your EPA regional representative as listed in 40 CFR 63.13 of subpart A (General Provisions).

B. What should I consider as I prepare my comments to EPA?

Do not submit information containing CBI to EPA through *www.regulations.gov* or e-mail. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID EPA-HQ-OAR–2006–0897. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

C. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this proposed action will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of this proposed action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/*. The TTN provides information and technology exchange in various areas of air pollution control.

D. When would a public hearing occur?

If anyone contacts EPA requesting to speak at a public hearing concerning the proposed rules by April 16, 2007, we will hold a public hearing on April 19, 2007. If you are interested in attending the public hearing, contact Ms. Pamela Garrett at (919) 541–7966 to verify that a hearing will be held.

E. How is this document organized?

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II. Background Information for Proposed Area Source Standards

Section 112(k)(3)(B) of the Clean Air Act (CAA) requires EPA to identify at least 30 hazardous air pollutants (HAP) that pose the greatest potential health threat in urban areas, and section 112(c)(3) requires EPA to regulate the area source [1] categories that represent 90 percent of the emissions of the 30 ''listed'' HAP (''urban HAP''). We implemented these listing requirements through the Integrated Urban Air Toxics Strategy (64 FR 38715, July 19, 1999).[2] Sierra Club sued EPA, alleging a failure to complete standards for the source categories listed pursuant to CAA section 112(c)(3) within the timeframe specified by the statute. See *Sierra Club* v. *Johnston,* No. 01–1537, (D.D.C.). On March 31, 2006, the court issued an order requiring EPA to promulgate standards under CAA section 112(d) for those area source categories listed pursuant to CAA section 112(c)(3).

Among other things, the order requires that, by June 15, 2007, EPA complete standards for six area source categories. We have selected seven area source categories to meet this obligation even though standards are required for only six area sources categories. The seven area source categories that we have selected to meet this obligation are: (1) Acrylic and Modacrylic Fibers Production; (2) Carbon Black Production; (3) Chemical Manufacturing: Chromium Compounds; (4) Flexible Polyurethane Foam Production; (5) Flexible Polyurethane Foam Fabrication Operations; (6) Lead Acid Battery Manufacturing; and (7) Wood Preserving.

We listed Flexible Polyurethane Foam Fabrication Operations as an area source category under CAA section 112(c)(3) as part of the 1999 Integrated Urban Strategy (64 FR 38721, July 19, 1999). On June 26, 2002, we amended the area source category list by adding source categories, including Acrylic and Modacrylic Fibers Production, Flexible Polyurethane Foam Production, Lead Acid Battery Manufacturing, and Wood Preserving (67 FR 43112, 43113). On November 22, 2002, we added Carbon Black Production and Chemical Manufacturing: Chromium Compounds to the area source category list (67 FR 70427, 70428).

The inclusion of each of these source categories on the section 112(c)(3) area source category list is based on 1990 emissions data, as EPA used 1990 as the baseline year for that listing. The Acrylic and Modacrylic Fibers area source category listing was based on emissions of the HAP acrylonitrile (AN). Emissions of chromium were the basis for the listing of the Chemical Manufacturing: Chromium Compounds source category. The Lead Acid Battery Manufacturing area source category listing was based on emissions of lead and cadmium. The listing of Carbon Black Production was based on HAP emissions of polycyclic organic matter (POM). The listings of Flexible Polyurethane Foam Production and Flexible Polyurethane Foam Fabrication Operations were based on HAP emissions of methylene chloride, and the listing of Wood Preserving was based on HAP emissions of arsenic, chromium, methylene chloride, and dioxin.

Under CAA section 112(d)(5), the Administrator may, in lieu of standards requiring maximum achievable control technology (MACT) under section 112(d)(2), elect to promulgate standards or requirements for area sources ''which provide for the use of generally available control technologies or management practices by such sources to reduce emissions of hazardous air pollutants.'' Under section 112(d)(5), the Administrator has the discretion to use generally available control technology or management practices (GACT) in lieu of MACT. Pursuant to section 112(d)(5), we have decided not to issue MACT standards and concluded that GACT is appropriate for these seven source categories.

Legislative history describes GACT as standards or requirements reflecting application of generally available control technology or management practices, that is, ''methods, practices and techniques which are commercially available and appropriate for application by the sources in the category considering economic impacts and the technical capabilities of the firms to operate and maintain the emissions control systems'' (Senate Report Number 101–228, December 20, 1989). Consistent with the legislative history, in addition to considering technical capabilities of the facilities and the availability of control measures, we may consider costs and economic impacts in determining GACT, which is particularly important when developing regulations for source categories that may have few establishments and many small businesses, or when determining whether additional control is necessary for sources with emissions that are already well controlled as a result of other existing or applicable standards.

Determining what constitutes GACT involves considering the control technologies and management practices that are generally available to the area sources in the source category. We also consider the standards applicable to major sources in the same industrial sector to determine if the control technologies and management practices are transferable and generally available to area sources. In appropriate circumstances, we may also consider technologies and practices at area and major sources in similar categories to determine whether such technologies and practices could be considered generally available for the area source category at issue. Finally, as noted above, in determining GACT for a particular area source category, we consider the costs and economic impacts of available control technologies and management practices on that category.

Existing facilities in the area source categories at issue in this proposal are currently well controlled as a result of State and national standards and permitting requirements for criteria pollutants that obtain co-control of HAP. There is only one area source plant in the U.S. in the Acrylic and Modacrylic Fibers Production area

[1] An area source is a stationary source of HAP emissions that is not a major source. A major source is a stationary source that emits or has the potential to emit 10 tons per year (tpy) or more of any HAP or 25 tpy or more of any combination of HAP.

[2] Since its publication in the Integrated Urban Air Toxics Strategy in 1999, the area source category list has undergone several amendments.

source category, and this plant is currently subject to State permit requirements. The two area source plants that manufacture chromium compounds and the one area source plant in the Carbon Black Production area source category are well controlled as a result of title V permit requirements for the control of criteria pollutants, which provide co-control of urban HAP. We believe that all of the 58 area source plants in the Lead Acid Battery Manufacturing area source category can achieve the requirements of the new source performance standard (NSPS) for lead-acid battery manufacturing plants at 40 CFR part 60, subpart KK. Facilities constructed, reconstructed, or modified after 1982 are already subject to the NSPS.

There are hundreds of facilities in the Flexible Polyurethane Foam Production and Flexible Polyurethane Foam Fabrication area source categories, which were listed because of the use of methylene chloride. The vast majority of these facilities no longer use methylene chloride in the processes for several reasons, including State air emissions standards and worker exposure limits established by the Occupational Safety and Health Administration (OSHA).

There are approximately 400 area source facilities in the wood preserving area source category. All of these facilities are well controlled in terms of metal HAP (i.e., chromium and arsenic) emissions and dioxin emissions. These facilities have also discontinued the use of methylene chloride.

III. Proposed Area Source NESHAP for Acrylic and Modacrylic Fibers Production

A. What area source category is affected by the proposed NESHAP?

The Acrylic and Modacrylic Fibers Production area source category consists of facilities engaged in the manufacture of synthetic fibers made from AN. Acrylic fibers are synthetic fibers in which the fiber-forming substance is any long-chain synthetic polymer composed of at least 85 percent by weight of AN. Modacrylic fibers are composed of 35 to 85 percent by weight of AN.

There are currently four plants in the U.S. that are known to produce acrylic and modacrylic fibers. Three of these plants are major sources. The fourth plant is an area source and is located in an urban area (Decatur, Alabama). The area source plant produces polyacrylonitrile that is primarily used as a feed stock for the production of carbon fibers.

B. What are the production processes and emissions points at facilities that manufacture acrylic and modacrylic fibers?

Acrylonitrile is the only urban HAP that was reported to be released during the production of acrylic and modacrylic fibers at the one known existing area source plant. The AN is fed to a polymerization reactor where the reaction (polymerization) takes place. The area source plant uses a suspension process in which insoluble beads of polymer are formed in the reactor. Residual unreacted AN is removed from the polymer in a monomer recovery column and is recycled to the process. After removal of the residual AN, the resulting polymer is spun into fibers. Fibers are formed by forcing the viscous polymer solution, referred to as ''dope,'' through the small orifices of a spinnerette and immediately solidifying or precipitating the resulting filaments.

At the area source plant, two 100,000 gallon storage tanks that receive the purchased AN monomer are controlled by internal floating roofs and are subject to the NSPS for volatile organic liquids (40 CFR part 60, subpart Kb). A packed column scrubber controls emissions from the polymerization process equipment, including storage tanks, recovered monomer tanks, monomer measuring tanks, monomer preparation tanks, monomer feed tanks, slurry receiver tanks, polymerization reactors, and drum filters. A second packed column scrubber controls emissions from the monomer recovery process, including polymer holding tanks, polymer buffer tanks, the monomer vacuum pump flush drum, and the drum filter vacuum pump flush drum.

Many of the pumps which move AN at this facility are canned motor pumps, which have no shaft protrusion to seal. The common leak point on other types of pumps is the seal for the shaft protrusion; consequently, canned motor pumps by design reduce leakage. Most of the piping is connected by welding rather than flanges, which reduces emissions from pipe connectors.

C. What are the proposed requirements for area sources?

1. Applicability and Compliance Dates

These proposed NESHAP apply to any existing or new acrylic or modacrylic fibers production plant that is an area source. We are proposing that owners or operators of existing sources comply with all the requirements of the area source NESHAP by 6 months after the date of publication of the final rule in the **Federal Register**. A new affected source would be required to comply by the date of publication of the final rule in the **Federal Register** or upon initial startup, whichever is later.

2. Proposed Emissions Standards

Existing sources. The proposed standards for existing area sources apply to process vents from the polymerization process, process vents from monomer recovery, spinning lines at plants that do not have a monomer recovery process, and AN storage tanks. We are proposing to adopt the State permit requirements applicable to the one existing area source as the NESHAP for existing acrylic and modacrylic fiber production area sources. The State operating permit for the existing area source establishes numerical limits for AN emissions from the control devices for polymerization process equipment and monomer recovery process equipment. The permit also establishes operating limits for the scrubbers.

The control device for polymerization process equipment would be subject to an AN emissions limit of 0.2 pound per hour (lb/hr). A control device operating limit would require a minimum daily average water flow rate to the scrubber of 50 liters per minute (l/min). The control device for emissions from the monomer recovery process equipment would be subject to an AN emissions limit of 0.05 lb/hr, and the daily average water flow rate must not drop below 30 l/min.

This proposed rule does not include requirements for spinning lines for existing sources that remove residual AN using a monomer recovery process prior to spinning. (See section D.1 of this preamble.) However, existing sources that do not have a monomer recovery process prior to spinning must meet the requirements for spinning lines in 40 CFR part 63, subpart YY.

This proposed NESHAP for existing sources would require that AN storage tanks meeting certain capacity/vapor pressure conditions comply with one of three control options: (1) A fixed roof in combination with an internal floating roof, (2) an external floating roof, or (3) a closed vent system and control device.

New sources. The proposed standards for new area sources apply to process vents, fiber spinning lines, AN storage tanks, process wastewater, maintenance wastewater, and equipment leaks. The proposed process vent requirements apply to each vent stream with an AN concentration of 50 parts per million by volume (ppmv) or greater and a flow rate of 0.005 cubic meters per minute or greater. The owner or operator would be required to control AN emissions from process vents meeting this applicability criteria by reducing uncontrolled

emissions by 98 weight percent or meeting an emissions limit (20 ppmv) by venting vapors through a closed vent system to a recovery device, control device, or flare. The owner or operator would be required to determine which process vents meet the applicability criteria by using the procedures and methods in § 63.1104 of subpart YY. The closed vent system, recovery or control device, and flare would be subject to the applicable testing, monitoring, recordkeeping, and reporting requirements in 40 CFR part 63, subpart SS. The owner or operator would be required to submit a monitoring plan if another type of control device is used.

The proposed emissions limits for fiber spinning lines at new sources require the owner or operator to: (1) Reduce AN emissions by 85 weight-percent (e.g., by venting emissions from a total enclosure through a closed vent system to a control device that meets the requirements in 40 CFR part 63, subpart SS), (2) reduce AN emissions from the spinning line to 0.5 pounds of AN per ton (lb/ton) of acrylic and modacrylic fiber produced, or (3) reduce the AN concentration of the spin dope to less than 100 parts per million by weight (ppmw). The requirements in 63.1103(b)(4) of subpart YY would apply to an enclosure for a fiber spinning line.

For all AN storage vessels at a new area source, the owner or operator would be required to: (1) Reduce AN emissions by 98 weight-percent by venting emissions through a closed vent system to any combination of control devices as specified in § 63.982(a)(1) of subpart SS or reduce AN emissions by 95 weight-percent or greater by venting emissions through a closed system to a recovery device as specified in § 63.993 of subpart SS; or (2) comply with the equipment standards for internal or external floating roofs in 40 CFR part 63, subpart WW.

Process wastewater and maintenance wastewater at new sources would be subject to the requirements in § 63.1106(a) and (b) of subpart YY. The owner or operator would also be required to comply with the equipment leak requirements in subpart YY. Subpart YY applies the requirements in either subpart TT or UU to equipment that contains or contacts 10 percent by weight or greater of AN and that operates at least 300 hours per year.

3. Compliance Requirements

We are proposing to include in this proposed NESHAP the monitoring, testing, recordkeeping, and reporting requirements in the State operating permit for the existing area source. Continuous parameter monitoring systems (CPMS) would be required to measure and record the scrubber water flow rates at least every 15 minutes. The owner or operator would determine compliance with the daily average operating limits for the scrubber water flow rates on a monthly basis and submit quarterly compliance reports to EPA or the delegated authority. Compliance with the operating limits would be determined on a monthly basis; quarterly compliance reports also would be required. The owner or operator would be required to keep records of each monthly compliance determination and retain the records for at least 2 years following the date of each compliance determination. If the daily average water flow rate falls below the operating limit, the owner or operator must notify EPA or the delegated authority within 10 days of the identification of the exceedance.

The owner or operator of an existing source would be required to conduct a performance test for each control device for polymerization process equipment and monomer recovery process equipment. A performance test would not be required for an existing source if a prior performance test has been conducted using the methods required by this rule, which are the requirements contained in § 63.1104 of subpart YY, and either no process changes have been made since the test, or the owner or operator can demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process changes.

For AN storage tanks at existing sources, the owner or operator would be required to comply with the applicable testing, inspection, and notification procedures in 40 CFR 60.113b(a) and the recordkeeping and reporting requirements in 40 CFR 60.115b and 60.116b of subpart Kb. The testing, monitoring, recordkeeping, and reporting requirements in 40 CFR part 65, subpart C would apply if the owner or operator selected to comply with the part 65 control option for AN storage tanks. See 40 CFR 60.110b(e).

The owner or operator of an existing area source would be required to comply with certain notification requirements in 40 CFR 63.9 of the General Provisions (40 CFR part 63, subpart A). These requirements would include a notification of applicability and a notification of compliance status. We are also proposing that the owner or operator comply with the requirements for startup, shutdown, and malfunction (SSM) plans, reports, and records in 40 CFR 63.6(e)(3).

In the notification of compliance status required in 40 CFR 63.9(h), the owner or operator of an existing source may certify initial compliance with the emissions limits based on a previous performance test if applicable. The owner or operator must also certify initial compliance with the NSPS requirements in 40 CFR part 60, subpart Kb.

The owner or operator of a new area source would be required to perform assessments [3] to identify affected process vents, equipment, and wastewater streams; conduct initial performance tests and/or compliance demonstrations; and comply with the monitoring, inspection, recordkeeping, and reporting requirements in each applicable subpart. The testing, monitoring, recordkeeping, and reporting requirements in the subparts described above, which we are adopting in this proposed rule, vary according to the emissions point and control option (e.g., subpart SS for process vents). The owner or operator of a new area source would also be required to comply with all of the NESHAP General Provisions (40 CFR part 63, subpart A), including requirements for notifications; performance tests and reports; SSM plans and reports; recordkeeping, and reporting. We have identified in the proposed NESHAP the General Provisions of 40 CFR part 63 applicable to existing and new sources.

D. What is our rationale for selecting the proposed standards for area sources?

1. Selection of Proposed Standards

Existing sources. The process vents at the existing area source plant are controlled by packed bed scrubbers and are subject to emissions limits established in the State operating permit. Emissions from the polymerization process equipment are limited to 0.2 lb/hr. This process equipment includes process storage tanks, recovered monomer tanks, monomer measuring tanks, monomer preparation tanks, monomer feed tanks, the polymerization reactors, and drum filter. Emissions from the monomer recovery process equipment are limited to 0.05 lb/hr. These process units include the polymer holding tank, polymer buffer tank, monomer vacuum pump flush drum, and the drum filter vacuum pump flush drum. Test data for these two process vents show that the vents are well controlled because the

[3] These assessments are used to determine which process vents and wastewater streams must be controlled.

facility achieves the level of control required for major sources subject to 40 CFR part 63, subpart YY. We have determined that the State operating permit limits are GACT for process vents at existing area sources.

The fiber spinning line at the existing area source plant is not a source of AN emissions because the residual monomer is stripped from the polymer in a monomer recovery column prior to spinning. However, other existing facilities might become area sources in the future, and they might not have a monomer recovery process. Consequently, we are proposing that any existing source without a monomer recovery process must reduce the residual AN concentration in the polymer by removing residual monomer prior to spinning or install an enclosure for the spinning line and vent the emissions to a control device. Existing area sources without a monomer recovery process must meet requirements for fiber spinning lines in 40 CFR part 63, subpart YY. We have determined that the requirements in 40 CFR part 63, subpart YY are GACT for existing area sources without a monomer recovery process.

The AN storage tanks at the existing area source plant are subject to the NSPS for volatile organic liquids (40 CFR part 60, subpart Kb). The NSPS requires that a storage tank meeting certain capacity/vapor pressure conditions comply with either the requirements for storage vessels in subpart C of 40 CFR part 65 (Consolidated Federal Air Rules) or the NSPS requirements for a fixed roof in combination with an internal floating roof, an external floating roof, or a closed vent system and control device. The AN storage tanks at the existing area source are equipped with internal floating roofs to comply with the NSPS requirements. The controls in the NSPS are currently being applied to AN storage tanks and are the types of controls generally applied to tanks storing volatile organic liquids. Consequently, we determined that the controls required by the NSPS are GACT for storage tanks at existing sources.

The potential for emissions from equipment leaks is low at the existing area source plant because of the use of canned motor pumps and pipes connected in large part by welding rather than flanges. A fugitive emissions survey using EPA's protocol for estimating emissions from equipment leaks coupled with capture and measurement of leaks resulted in estimated emissions of only 0.5 tpy of AN (assuming any leak that was detected emitted for the full year). A leak detection and repair program for this plant would cost several thousand dollars in labor and in capital for the monitoring equipment. After considering the low level of current emissions, the additional costs, and the small emissions reduction that would be achieved by a leak detection and repair program, we propose that GACT for existing area sources is no additional control for equipment leaks.

Wastewater at the existing plant is sent to a biological treatment unit to degrade AN. Emissions of organic compounds from wastewater can be reduced by steam stripping the wastewater to remove and recover the organics. We estimate that the capital cost of steam stripping to remove AN from the wastewater at the existing area source plant is $700,000 with a total annualized cost of $630,000 per year. Even assuming 90 percent removal by the steam stripper, the emissions reduction would be 7 tons per year. We propose to conclude that pretreatment using steam stripping is not GACT because of the high cost effectiveness of processing a low concentration stream with a high volumetric flow rate. This conclusion is consistent with previous cost effectiveness analyses such as those performed for major sources where EPA determined that it is not cost effective to apply controls to wastewater below certain cutoffs (e.g., a concentration less than 1,000 ppmw and a flow rate less than 10 liters per minute (57 FR 62608, December 31, 1992). The process wastewater at the existing area source is below these cutoffs. Consequently, we are not proposing additional controls for wastewater at the existing area source plant and conclude that GACT is the current level of control.

We are alternatively proposing that GACT for this existing area source is no further emission reduction. We request comment on the basis, consistent with section 112(d)(5), for asserting that GACT is no further control for the existing source. We request comment on this issue because the standard proposed above will not result in any emission reductions beyond what is already required by the State permit to which the existing facility is already subject.

New Sources. Test results for the control devices applied to process vents at the existing area source show that a standard of 98 weight-percent reduction or an outlet concentration of 20 ppmv or less has been achieved by the controls we propose as GACT at the existing source.[4] Consequently, we are proposing that GACT for process vents at a new area source is a 98 weight-percent reduction of AN emissions, an outlet concentration of 20 ppmv or less, or venting emissions to a flare. This format of the proposed standard is more appropriate for new sources than a process vent limit expressed in lb/hr (as applied to the existing area source) because we do not know what the size, configuration, or emissions potential of a new source might be.

As discussed earlier, the fiber spinning line at the existing area source plant is not a source of AN emissions because the residual monomer is stripped from the polymer in a monomer recovery column prior to spinning. However, we cannot be certain what process configuration a new source might use or that it would have a monomer recovery system. Consequently, we are proposing that a new source must reduce the residual AN concentration in the polymer by removing residual monomer prior to spinning or install an enclosure for the spinning line and vent the emissions to a control device. Data from acrylic and modacrylic fiber production indicates that a monomer recovery system can reduce the AN concentration in the spin dope to less than 100 ppmw, which we are proposing as GACT for new area sources. We are proposing alternatives to the AN residual concentration limit for new sources that are the same as the alternatives that are available for major sources in 40 CFR part 63, subpart YY. One alternative is to reduce AN emissions from the spinning line by 85 weight-percent or more. The second alternative is to reduce AN emissions from the spinning line to less than or equal to 0.5 lb/ton of acrylic and modacrylic fiber produced.

For storage tanks at new area sources, we are proposing to adopt the requirements in 40 CFR part 63, subpart YY. These requirements have been applied to AN storage tanks at other acrylic and modacrylic fiber plants and represent GACT for new sources because they are cost effective and can be easily included in the design and construction of a new source.

We also evaluated emissions controls and management practices for equipment leaks at new sources. We know that equipment leaks are well controlled at the existing area source facility; however, we do not know with assurance that a new source will have primarily leakless equipment. In addition, our studies of synthetic organic chemical plants indicate that leak inspection and repair requirements are cost effective and not overly burdensome. Consequently, we are

[4] This is also the level of control that major sources must meet for process vents.

proposing that new area sources be subject to the same equipment leak provisions as those applied to major sources in 40 CFR part 63, subpart YY.

For wastewater streams at new area sources, we do not know what flow rates, concentrations and emissions potential might occur, but our studies of wastewater treatment controls indicate that it is cost effective to control these emissions when the concentration of AN is high. For example, at most acrylic and modacrylic fiber plants, all wastewater streams with a concentration of 10,000 parts per million by weight (ppmw) or more must be controlled, as well as streams with both a concentration of 1,000 ppmw or more and a flow rate of 10 l/min or more. Controls are not required for wastewater streams below these cutoffs because they are not cost effective. Thus we are proposing that GACT for new sources is the control of wastewater streams that exceed the cutoffs of concentration and/or flow rate as specified in subpart YY.

2. Selection of Proposed Compliance Requirements

We have reviewed the compliance requirements in the State operating permit, the NSPS for volatile organic liquid storage tanks, and other requirements that apply to the existing area source plant, and we propose that these requirements are sufficient to ensure compliance with the proposed emissions standards. Therefore, we are proposing to include the inspection, monitoring, recordkeeping, and reporting requirements that apply to the existing area source plant in this proposed rule for existing sources.

We are proposing to require that an existing area source be subject to certain notification requirements in the NESHAP General Provisions (40 CFR part 63, subpart A). Because permit information for the existing facility does not identify requirements for an SSM plan, we are also proposing to require the owner or operator of an existing area source to comply with the SSM requirements in 40 CFR 63.6(e)(3). We are proposing to allow additional time (6 months after promulgation) to allow for preparation of the plan.

We have also reviewed the compliance requirements in the subparts of part 63 that would apply to process vents, storage tanks, equipment leaks, and wastewater at new area sources as a result of this proposed rule. These requirements are sufficient to ensure compliance with the proposed emissions limits and management practices. Therefore, we are proposing to include the testing, monitoring, recordkeeping, and reporting requirements in each applicable subpart in this proposed rule for new sources.

We are also proposing to apply to new sources the notification, testing, monitoring, operation and maintenance, recordkeeping, and reporting requirements in the part 63 General Provisions (40 CFR part 63, subpart A). The General Provisions are necessary for effective application of the standard for new area sources and are, therefore, incorporated into the proposed rule. We propose that these requirements are sufficient to ensure compliance with the proposed emissions limits and management practices for new sources.

IV. Proposed Area Source NESHAP for Carbon Black Production

A. What area source category is affected by the proposed NESHAP?

The Carbon Black Production area source category includes any facility that produces carbon black by the furnace black process, thermal black process, or the acetylene decomposition process. Carbon black is used primarily as a reinforcing agent for rubber and is used largely in the manufacturing of automotive tires. It is also used as a colorant in inks, paints, plastics, and paper.

Currently, there are 20 carbon black production facilities operating in the U.S. Nineteen of these facilities are major sources of HAP emissions and are subject to NESHAP requirements for carbon black production in 40 CFR part 63, subpart YY. According to the National Emissions Inventory (NEI) and the Toxics Release Inventory (TRI), one carbon black production facility is an area source of HAP emissions. We are requesting comments on whether there are any other area sources in this source category.

B. What are the production processes and emissions points at facilities that manufacture carbon black?

A carbon black unit (CBU) consists of the equipment used to produce carbon black by either the furnace, thermal or acetylene decomposition processes. The major components of the CBU include: (1) Feedstock and raw material storage tanks; (2) production unit reactors; (3) separation filters; (4) wet or dry pelletization equipment and densification equipment; (5) final product silos and packaging for pellets and powders; and (6) shipping storage areas.

Carbon black is produced by the furnace black process via thermal-oxidative decomposition in a closed system. The feedstock is primarily aromatic oils based on crude oil. Feedstock is injected into the reactor and is converted to carbon black. The reactor is heated by a fuel, usually natural gas.

The thermal black process produces carbon black via thermal decomposition in a cyclic process. The primary feedstock is natural gas. The process generally includes two vertical reactors in parallel. While one reactor is heating, the other reactor is in the decomposition cycle.

The acetylene black process uses an acetylene feedstock to produce carbon black via thermal decomposition in a continuous process. The acetylene black reactor is similar to the reactor for the thermal black process; however, since it is a continuous process, usually only one reactor is used.

The remaining processes for the furnace black, thermal black and acetylene black production processes are similar. The carbon black and tailgas stream from the reactor is cooled in a heat exchanger. Energy from the carbon black and tailgas stream is used to preheat combustion air for the reactor. Following the heat exchanger, a secondary quench chamber is used to further cool the carbon black and tailgas stream.

Carbon black is separated from the tailgas in the main separation filter. Tailgas may be collected and used as fuel in the dryer (if present), burned to preheat the feedstock (if a preheater is present), vented to the atmosphere, or vented to a combustion device for destruction.

Carbon black is separated from the conveying air in the process filter. Solid contaminants (*e.g.*, coke particles, abraded particles from the refractory lining of the furnace, or rust particles) are removed from the carbon black in the grit separator.

Initial densification of the carbon black takes place in the surge tank, which also acts as a buffer to maintain constant production levels. Carbon black is processed into pellets in either a wet pelletizer or a dry pelletizer. In the wet pelletization process, water, and sometimes additives, is injected into the pelletizer and the carbon black leaves as wet pellets and are dried in the dryer. Tailgas may be used as fuel in the dryer for external heating. Carbon black and steam from the dryer exhaust are separated in the purge filter and the carbon black is recycled to the process filter.

In the dry pelletization process, the pelletizer is a rotating drum. A portion of the pelletized carbon black is recycled to the inlet of the drum to act as seeds for the new pellets. Pelletized

carbon black is housed in the storage silo until it is discharged to trucks or rail cars, intermediate bulk storage, or packaging.

The Carbon Black Production area source category was listed for regulation due to emissions of the urban HAP POM. Benzene is another urban HAP emitted from the CBU. The HAP are released into the atmosphere from the tailgases from the reactors. The carbon black and tailgas stream is sent to a baghouse where the carbon black is separated from the tailgas. After separation of the carbon black product, the tailgas is either emitted to the atmosphere or sent to a combustion control device.

C. What are the proposed requirements for area sources?

1. Applicability and Compliance Dates

The proposed NESHAP applies to each new or existing carbon black production facility that is an area source of HAP. Because the one existing area source is already meeting requirements that are the same as those in this proposed NESHAP, we are proposing that an existing affected source comply by the date of publication of the final rule in the **Federal Register**. A new affected source would be required to comply by the date of publication of the final rule in the **Federal Register** or upon initial startup, whichever is later.

2. Proposed Emissions Standards

We are proposing that the owner or operator of an existing or new source be required to control HAP emissions from each carbon black production main unit filter process vent that has a HAP concentration equal to or greater than 260 ppmv. The specific control requirements are: (1) Reduce emissions of HAP by using a flare meeting all the requirements of 40 CFR part 63, subpart SS; or (2) reduce total HAP emissions by 98 weight-percent or to a concentration of 20 ppmv, whichever is less, by venting emissions through a closed vent system to any combination of control devices meeting the requirements 40 CFR 63.982(a)(2).

3. Compliance Requirements

For existing and new area sources, we are proposing to adopt the testing, monitoring, recordkeeping, and reporting requirements in subpart YY. Compliance with the proposed emissions limit for existing and new area sources would be demonstrated by monitoring the operating parameters of the control device or devices selected to comply with the requirements of the NESHAP. The proposed NESHAP specifies requirements for the initial notification, the notification of compliance status, periodic reporting, and SSM requirements.

The owner or operator of an existing or new area source would be required to comply with the subpart YY notification requirements in 40 CFR 63.1110. In the notification of compliance status required in 40 CFR 63.1110(d), the owner or operator of an existing source may demonstrate initial compliance with the proposed HAP emissions standards based on the results of a performance test that has been previously conducted provided certain conditions are met (*e.g.*, using the same methods as the test methods in the proposed rule).

D. What is our rationale for selecting the proposed standards for area sources?

1. Selection of Proposed Standards

Based on information in the NEI and TRI, we identified only one existing carbon black production facility that is an area source. We are requesting comments on whether there are any other area sources in this source category. This carbon black production facility operates emissions control systems that capture and control tailgases from their four CBUs. The tailgases from each CBU are routed to control devices (two are routed to a flare and two are routed to a thermal incinerator) that achieve high-efficiency removal of volatile organic compounds (VOC), including polycyclic organic matter (POM) and benzene.

The existing area source is currently operating under a title V permit, which requires a 98 weight-percent VOC emissions reduction. The facility's ability to demonstrate compliance with their title V permit emissions limits on a long-term basis indicates that the facility owner has the technical and economic capabilities to continue to reduce VOC emissions (including POM and benzene) sufficiently to achieve these limits. Further, although the existing area source facility utilizes the furnace black production process, a 98 weight-percent emissions reduction would apply equally to all types of production processes. Consequently, we do not distinguish between the different carbon black production processes.

After reviewing the existing facility's title V permit requirements, we concluded that the permit requirements are equivalent to the provisions of 40 CFR 63, subpart YY, which is the rule to which major source carbon black facilities are subject. Further, the facility has applied for renewal of their title V permit to specifically include the requirements of subpart YY for their CBU. Because control technologies to reduce VOC emissions also reduce POM and benzene emissions, the 98 weight-percent VOC emission reduction in their title V permit is equivalent to the 98 weight-percent HAP level of control specified in subpart YY. We have no reason to believe that this emissions reduction is infeasible or inappropriate for all area sources in this category. Therefore, we have determined that a 98 weight-percent HAP emissions reduction is GACT for existing and new carbon black production area source facilities, which may be achieved using one or more control devices or a flare subject to § 63.11 of the NESHAP General Provisions (40 CFR part 63, subpart A).

In addition to the 98 weight-percent level of control, we have established that for low concentration streams (*e.g.*, streams with concentrations less than about 1,000 ppmv), a 98 weight-percent reduction may not be achievable for all process vents from the main unit filter (65 FR 76423). Therefore, we have determined that a HAP concentration limit of 20 ppmv (corrected to 3 percent oxygen if a combustion device is the control device and supplemental combustion air is used to combust the emissions) is appropriate as GACT for low-concentration streams.

The subpart YY NESHAP also include a 260-ppmv control applicability cutoff. This cutoff represents the lowest control device inlet concentration reported at one of the best-controlled facilities. We do not have available information to indicate that the single existing area source controls process vent emissions streams with concentrations below this level. Therefore, we have included the 260-ppmv control applicability cutoff in this proposed area source NESHAP.

We are alternatively proposing that GACT for this existing area source is no further emission reduction. We request comment on the basis, consistent with section 112(d)(5), for asserting that GACT is no further control for the existing source. We request comment on this issue because the standard proposed above will not result in any emission reductions beyond what is already required by the Federal permit to which the existing facility is already subject.

2. Selection of Proposed Compliance Requirements

The existing carbon black area source facility's title V permit requires operating parameter monitoring, recordkeeping, and periodic reporting. We reviewed these compliance requirements and concluded that they

are sufficient to ensure compliance with the proposed emissions standards for existing and new sources. Because these requirements are equivalent to those in 40 CFR part 63, subpart YY, we have adopted the subpart YY compliance requirements in this proposed rule. These requirements include operating parameter monitoring, initial performance testing, notifications, and periodic reports.

Because permit information for the existing facility does not identify requirements for an SSM plan, we are proposing that the owner or operator of an existing area source comply with the SSM requirements in 40 CFR 63.1111. Section 63.1111(a)(1) of subpart YY requires that the title V permit for a source include provisions for an SSM plan.

V. Proposed Area Source NESHAP for Chemical Manufacturing: Chromium Compounds

A. What area source category is affected by the proposed NESHAP?

The area source category, ''Chemical Manufacturing: Chromium Compounds,'' includes facilities that use chromite ore as the basic feedstock to manufacture chromium compounds, primarily sodium dichromate, chromic acid, and chromic oxide. There are only two plants in this area source category, and both are located in urban areas. One plant is located in Castle Hayne, North Carolina (near Wilmington) and the other is in Corpus Christi, Texas.

Most of the sodium dichromate produced by the two plants is used to make chromic acid. Sodium dichromate is also used in leather tanning, chromic oxide production, pigments manufacture, textile dyeing, and in the manufacture of numerous other products. Chromic acid is used in the metal finishing industry to produce resistant coatings for a variety of base metals. Other uses include decorative plating, conversion coatings, and metal coloring compounds. The two main uses of chromic oxide are in pigments and refractories.

B. What are the production processes and emissions points at facilities that manufacture chromium compounds?

Although the basic processes at the two plants are similar, there are some subtle differences in the processing steps, and the two plants have somewhat different emissions points and control configurations. Consequently, separate profiles of the processes and emissions controls are provided in sections V.B.1 through V.B.4 of this preamble.

1. Sodium Chromate Production

The main feedstock for the manufacturing process is chromite ore imported from South Africa and Finland, typically containing about 45 percent or more chromium oxide. At the Texas plant, the chromite ore is dried and ground in a ball mill. The ground ore is mixed with alkaline material (soda ash, sodium bicarbonate, and sodium hydroxide) and fed to a rotary kiln where it is heated to about 2,000 degrees Fahrenheit (°F). This process (known as ''roasting'') oxidizes the chromite ore, converting the majority of the chromium in the ore from trivalent to hexavalent chromium. Baghouses on the ore drying and grinding unit control emissions. Baghouses also control emissions from the rotary kiln during roasting. After roasting, the material typically contains 20 to 40 percent hexavalent chromium as sodium chromate and 10 to 20 percent trivalent chromium. The material exiting the rotary kiln is quenched with water in quench tanks. The quenching process is controlled by a wet scrubber and wet electrostatic precipitator.

The resulting ore slurry goes through a belt filter to filter and purify the sodium chromate. The filters remove solid aluminum, vanadium, and calcium residues. Sodium dichromate is added to the ore slurry to aid in the removal of aluminum. Calcium hydroxide (lime) is added to remove vanadium. Soda ash solution is added to remove calcium. A baghouse on the impurity treatment and filtration units controls emissions.

Some of the impurities from the impurity treatment and filtration unit are placed in a secondary roasting kiln with sodium hydroxide and additional chromite ore for another round of chromium recovery. Roasted and quenched material from the secondary kiln travels to impurity treatment and filtration units for the same purification process described above for materials from the primary roasting unit. A baghouse on the secondary kiln and wet scrubber on the quench system control emissions.

At the North Carolina plant, the chromite ore is dried in rotary dryers and then pulverized in ball mills. The pulverized ore is prepared for roasting by mixing the ore with lime, soda ash, and recycled residue from the roasting kilns. Emissions from the ore drying and grinding units are controlled by cyclones and dry electrostatic precipitators. The kiln feed is fed to one of three rotary kilns in which the chromite ore is roasted. The hot gases generated in the kilns are sent to waste heat boilers for energy recovery. Emissions from the waste heat boilers travel to dry electrostatic precipitators and are vented through the main stack. The dry electrostatic precipitators process several gas streams, including emissions from the ore drying and grinding units, the roasting kiln waste heat boilers, the ore mixing unit and roasting kiln, and the post-leach ore residue drying unit.

After exiting the kiln, the hot kiln roast is quenched and leached with hot water in tanks to dissolve the water-soluble sodium chromate and form a sodium chromate slurry. The sodium chromate slurry is sent to a recycle unit where hydroclones separate unconverted ore residue from the sodium chromate solution. The ore residue is washed and filtered on a filter belt, dried, and recycled to the kiln. A system of cyclonic scrubbers and wet electrostatic precipitators on the quench tanks and filter unit are used to control emissions. Emissions from the ore residue dryer are controlled by a cyclone and the dry electrostatic precipitators described earlier.

2. Sodium Dichromate Production

At the Texas plant, the purified sodium chromate solution travels from the impurity treatment and filtration system to the electrolytic cell system for electrolytic acidification. Water is added to the electrolytic cells as well. This process converts the sodium chromate solution to sodium dichromate solution. Fiber bed filters on the electrolytic cell system control emissions. The sodium dichromate can be sold or used on-site in the production of chromic oxide or chromic acid.

Some sodium chromate solution is sent to a sodium chromate crystallization, evaporation, and drying unit to produce sodium chromate crystals. These crystals are then packaged for sale. Some sodium dichromate solution is also sent to a sodium dichromate crystallization, evaporation, and drying unit for production of sodium dichromate crystals. The crystals are sent to a packaging unit for packaging before sale. The emissions from the crystallization, evaporation, and drying units for the sodium chromate and sodium dichromate solutions are controlled by an entrainment separator and wet scrubber.

At the North Carolina plant, the sodium chromate product stream proceeds through a series of pH adjustment and filtration steps using sodium carbonate and sulfuric acid to remove impurities such as iron, aluminum, and other oxides from the

sodium chromate solution. The sodium chromate solution is neutralized to a pH of 8.5 to precipitate and allow filtration of the remaining ore residues. The sodium chromate liquor is mixed with a soda ash solution in the calcium precipitator unit to precipitate the calcium as calcium carbonate. The sodium chromate liquor is then filtered to remove the calcium carbonate. In the acidification unit, the filtered raw sodium chromate liquor is acidified to a pH of 4.0 with sulfuric acid to produce sodium dichromate. This solution is partially evaporated to 85 percent concentration and then centrifuged to separate sodium sulfate (salt cake) from the sodium dichromate solution. After separation from the salt cake, the sodium dichromate product solution is either stored in tanks from which, after dilution to the appropriate concentration, it is either sold as sodium dichromate product liquor or used as feedstock in the chromic acid plant. Some of the sodium dichromate solution is crystallized, centrifuged, and dried to form sodium dichromate crystalline product. Emissions from the crystallization area are controlled by an impingement plate scrubber and demister.

3. Chromic Acid Production

At the Texas plant, the production of chromic acid is performed by electrolytic reaction of sodium dichromate solution through a series of cells. Sodium dichromate solution is introduced into the anode side of an electrolytic cell, and water is introduced to the cathode side. Direct current causes a reaction on the anode side of the cell, producing chromic acid, sodium ions, and oxygen gas. Sodium ions migrate to the cathode side (water) of the cell through a membrane, which produces sodium hydroxide and hydrogen gas. The sodium dichromate/chromic acid solution (anode side) is withdrawn to be used as influent for the next cell line. The effluent from the anode side of the last stage is crystallized, centrifuged, dried, and packaged.

Three scrubbers are used to control emissions from chromic acid production. Emissions from the electrolytic cells are controlled by two scrubbers; one scrubber controls oxygen gas and hexavalent chromium emitted from the anode side of the cells and one controls hydrogen gas and hexavalent chromium from the cathode side of the cell. Drying, storage, and packaging operations are vented to the same wet scrubber.

At the North Carolina plant, the sodium dichromate liquor is further acidified with sulfuric acid to produce chromic acid crystals. The acidified slurry is filtered to recover the chromic acid and the filtrate is recycled to the sodium dichromate process. The chromic acid crystals are fed to a reactor where they are melted. The melted chromic acid produced in the reactor is cooled and then sent to a flaking process to produce the chromic acid flakes which are packaged and sold as final products. Emissions from the chromic acid area are controlled by a packed bed scrubber and demister.

4. Chromic Oxide and Chromium Hydrate Production

The Texas plant is the only facility producing chromic oxide and chromium hydrate. In the production of chromic oxide, ammonium sulfate and sodium dichromate solution that has been concentrated by evaporation are mixed and fed to a rotary roasting kiln to produce chromic oxide, sodium sulfate and nitrogen gas. The roast is quenched with water in which the chromic oxide is insoluble and the sodium sulfate is soluble. The mixture is washed in countercurrent thickeners, filtered, dried, milled, and packaged. To produce metallurgic grade chromic oxide and certain other grades, the chromic oxide is re-roasted in a secondary rotary kiln, quenched, filtered, dried, milled, and packaged.

The chromic oxide plant uses baghouses and scrubbers for emissions control; this production area has 10 bag houses and 11 scrubbers. Four baghouses control emissions from the ammonium sulfate storage and grinding area. Emissions from mixing of the sodium dichromate and ammonium sulfate are vented to a wet cyclone. Wet scrubbers control emissions from the quench tanks of both the primary and secondary roasting kilns. A baghouse, wet scrubber, and a mist eliminator control emissions from the primary roasting kiln. A wet scrubber controls emissions from the secondary roasting kiln. Filtration steps after both primary and secondary roasting are each vented to separate wet scrubbers. The dryer vents to a bag filter. Chromic oxide storage, grinding, and packaging steps are vented to six baghouses.

In the production of chromium hydrate, boric acid and concentrated sodium dichromate are mixed and fed to a furnace to produce a chromium hydrate ''clinker'' and sodium borate. The clinker is quenched with water. The mixture is then leached in tanks and filter presses to form chromium hydrate, then filtered, dried, milled, and packaged. Emissions controls include baghouses for boric acid grinding, chromium hydrate roasting, and chromium hydrate grinding and packaging.

C. What are the proposed requirements for area sources?

1. Applicability and Compliance Dates

The proposed NESHAP apply to the owner or operator of a new or existing area source that manufactures chromium compounds. We are proposing that owners or operators of existing sources comply with all the requirements of the area source NESHAP by 6 months after the date of publication of the final rule in the **Federal Register**. A new affected source would be required to comply by the date of publication of the final rule in the **Federal Register** or upon initial startup, whichever is later.

2. Proposed Emissions Standards

The proposed NESHAP requires new and existing facilities to operate a capture system that collects gases and fumes from each emissions source and conveys the gases to a PM control device. Emissions limits for PM, in lb/hr format, would be established based on the process rate of the emissions unit. These PM emissions limits would apply to more than 20 emissions units in the production of chromium compounds, including sodium chromate, sodium dichromate, chromic acid, chromic oxide, and chromium dehydrate at new and existing sources.

3. Compliance Requirements for Existing Area Sources

The control devices used at these facilities include baghouses, dry electrostatic precipitators, wet electrostatic precipitators, and wet scrubbers. The proposed monitoring requirements for existing area sources consist of inspection and maintenance requirements specific to the type of control device.

For a baghouse, this proposed NESHAP requires monthly visual inspections of the system ductwork and baghouse units for leaks. The plant owner or operator would also be required to conduct an annual inspection of the interior of each baghouse for structural integrity and condition of the filter fabric. For electrostatic precipitators, plants would be required to conduct: (1) A daily check to verify that the electronic controls for corona power and rapper operation are functioning, that the corona wires are energized, and that adequate air pressure is present on the rapper manifold; (2) a monthly visual inspection of the system ductwork,

cyclones (if applicable), housing unit, and hopper for leaks; and (3) a biennial internal inspection to determine the condition and integrity of corona wires, collection plates, plate rappers, hopper, and air diffuser plates. For wet electrostatic precipitators, plants would also be required to conduct a daily check to verify water flow and a biennial internal inspection to determine the condition and integrity of plate wash spray heads. For wet scrubbers, plants would be required to conduct: (1) A daily check to verify water flow to the scrubber; (2) a monthly visual inspection of the system ductwork and scrubber unit for leaks; and (3) an annual internal inspection for structural integrity and condition of the demister and spray nozzle.

The owner or operator of an existing plant would be required to record the results of each inspection, the results of any maintenance performed on the control device, and the date and time of each recorded action. The results of inspections and maintenance of control equipment would be recorded in a logbook (written or electronic). The logbook would be kept onsite and made available to the permitting authority upon request. The owner or operator of an existing plant would be required to report any deviations from the emissions limits or monitoring requirements in a semiannual report submitted to the permitting authority.

The owner or operator of an existing area source would be required to submit an initial notification of applicability and a notification of compliance status according to the requirements in 40 CFR 63.9 of the General Provisions (40 CFR part 63, subpart A). A performance test would not be required if a performance test has been conducted within the past 5 years using the specified test methods and either no process changes have been made since the test, or the owner or operator can demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process changes. We are also proposing that the owner or operator comply with either the requirements for SSM plans and reports in 40 CFR 63.6(e)(3) or with the malfunction requirements in this proposed rule that are based on the title V permit requirements. The permit requires a report if an event occurs that results in emissions in excess of a PM limit and lasts for more than 4 hours.

4. Compliance Requirements for New Area Sources

The owner or operator of a new source would be required to install and operate a bag leak detection system for each baghouse used to comply with a PM emissions limit. The requirements for the bag leak detection system are set forth in proposed section 63.11410(g). For additional information on bag leak detection systems that operate on the triboelectric effect, see ''Fabric Filter Bag Leak Detection Guidance'', U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, September 1997, EPA–454/R–98–015, NTIS publication number PB98164676. This document is available from the National Technical Information Service (NTIS), 5385 Port Royal Road, Springfield, VA 22161.

The owner or operator of a new source that uses a control device other than a baghouse must submit a monitoring plan to the permitting authority for approval. The plan must describe the control device, the parameters to be monitored, and the operating limits for the parameters established during a performance test.

The owner or operator of a new source would be required to demonstrate initial compliance with each applicable PM emissions limit by conducting a performance test according to the requirements in 40 CFR 63.7. EPA Method 5 or 5D (40 CFR part 60, appendix A), as applicable, would be used to determine the PM emissions. All of the testing, monitoring, operation and maintenance, recordkeeping, and reporting requirements of the part 63 General Provisions would apply to a new area source. We have identified in the proposed NESHAP the General Provisions of 40 CFR part 63 applicable to existing and new sources.

D. What is our rationale for selecting the proposed standards for area sources?

1. Selection of PM as a Surrogate for Chromium

The PM emissions from the various processes used for manufacturing chromium compounds contain the urban HAP chromium, and emissions control equipment that is designed and operated to control PM emissions also control chromium emissions. Both plants have title V operating permits that require PM emissions controls and establish emissions limits for PM. For these reasons, we decided to establish standards using PM as a surrogate for chromium emissions, which is the urban HAP that was the basis for the listing. Controlling PM emissions will control chromium emissions since they are contained within the PM—they are in the particulate form as opposed to the gaseous form. PM controls used at existing chromium plants are the same controls available to control particulate HAP metals such as chromium. These controls capture particulate HAP metals non-preferentially along with other PM, thus making PM a reasonable surrogate for chromium. We have used this approach in several other NESHAP in which PM was determined to be a surrogate for the HAP metals in the PM.

2. Selection of Proposed Standards

The two existing chromium compound production facilities currently hold title V operating permits issued by their respective State permitting agencies. Both permits contain PM emissions limits for all processes used to produce chromium compounds. We determined that the PM emissions limits applicable to these emissions sources are consistent with the expected performance of similar operations controlled by well-operated and maintained emission control devices. These control devices (baghouses, wet scrubbers, and wet and dry electrostatic precipitators) are widely used to control the emissions from both primary and secondary production of many different metals, they have been demonstrated to be effective at controlling emissions of metal HAP, they are cost effective, and they represent GACT for new and existing area sources in the chromium compounds manufacturing industry.

We reviewed the PM limits in the title V operating permits for both plants. The North Carolina plant has PM limits that are expressed in an equation as a function of process throughput. For example, as the process throughput decreases, the PM emissions limit in lb/hr also decreases. This equation is applied to each of the production processes for chromium compounds, and the allowable emissions limit based on throughput accounts for changes in production levels, which affects the level of emissions control that can be achieved. The Texas plant has emissions limits that are fixed in terms of allowable lb/hr and are independent of process throughput. A format that is fixed in lb/hr is not an appropriate approach for other existing plants or for new plants because it does not account for differences in size or capacity.

We determined that the format used in the title V permit for the North Carolina plant was appropriate for a national standard for new and existing area sources. This mechanism for determining the emissions limit accounts for differences in process rates at different plants and it accounts for changes in the process rate at a given plant over time. We have also determined that the Texas plant can achieve the proposed emissions limits

based on process throughput using their existing emissions control equipment. Consequently, we are proposing to apply this equation to determine emissions limits for each of the production processes at all new and existing area source plants for this national standard.

We are alternatively proposing that GACT for these existing area sources is no further emission reduction. We request comment on the basis, consistent with section 112(d)(5), for asserting that GACT is no further control for these existing sources. We request comment on this issue because the standard proposed above will not result in any emission reductions beyond what is already required by the Federal permits to which the existing facilities are already subject.

3. Selection of Proposed Compliance Requirements

We are proposing to base the compliance requirements for existing area sources on the operation and maintenance, recordkeeping, and reporting requirements in the title V permit of the area source located in North Carolina. The title V permit includes requirements for inspections and maintenance of each type of control device, semiannual reports of any deviation, and records of control device inspections and maintenance. In contrast, the compliance requirements for the Texas plant include very little with respect to monitoring or maintaining emissions control equipment. The requirements we are proposing are necessary to ensure emissions controls are maintained and operated properly on a continuing basis. The requirements do not pose a significant additional burden for the Texas plant that must implement them. We are allowing 6 additional months for existing area sources to prepare a startup, shutdown, and malfunction plan and implement the inspection and maintenance requirements for control devices.

We would require that the existing plants comply with limited initial notification requirements in 40 CFR 63.9 of the NESHAP General Provisions (40 CFR part 63, subpart A). In the notification of compliance status required by 40 CFR 63.9(h), the owner or operator would certify that equipment has been installed and is operating for each regulated emissions point and that the plant will comply with the inspection and maintenance requirements. The plant would be required to conduct a performance test to demonstrate initial compliance if a performance test has not been conducted in the past five years.

We are proposing to require bag leak detection systems for baghouses used at new area sources; a monitoring plan would be required if another type of control device is used. Bag leak detection systems are typical requirements for new sources of the size and complexity of chromium compound manufacturing facilities. In addition, these systems can be incorporated into the design and operation for new sources and would not require retrofitting or duplicative monitoring as would be the case if they were applied to existing sources.

For new area sources, we are also proposing to apply the notification, testing, monitoring, operation and maintenance, recordkeeping, and reporting requirements in the part 63 General Provisions (40 CFR part 63, subpart A). The General Provisions are necessary for effective application of the standard for new area sources. We propose that these requirements are sufficient to ensure compliance with the proposed emissions limits for equipment at new area sources.

VI. Proposed Area Source NESHAP for Flexible Polyurethane Foam Production and Fabrication

A. What area source categories are affected by the proposed NESHAP?

This proposed NESHAP applies to two area source categories: Flexible Polyurethane Foam Production and Flexible Polyurethane Foam Fabrication Operations. We are addressing these two area source categories in a single NESHAP due to similarity of their operations and because they are often co-located.

The Flexible Polyurethane Foam Production area source category includes any facility which manufactures foam made from a polymer containing a plurality of carbamate linkages in the chain backbone (polyurethane). Polyurethane is commonly made by reacting a polyisocyanate with an organic polyhydroxyl material in the presence of water. Application of blowing agents, catalysts, surfactants, and fillers transform the polyurethane into a foam with specialized properties.

There are three types of polyurethane foam production facilities: slabstock flexible polyurethane foam (slabstock foam), molded flexible polyurethane foam (molded foam), and rebond foam. Slabstock foam is produced in large continuous ''buns'' that are then cut into the desired size and shape. Slabstock foam is used in a wide variety of applications, including furniture and mattresses. Molded foam is produced by ''shooting'' the foam mixture into a mold of the desired shape and size. Molded foam is used in office furniture, automobile seats, novelties, and many other applications. Rebond foam is made from scrap foam that is converted into a material primarily used for carpet underlay.

Prior to the promulgation of the NESHAP for major sources of foam production (40 CFR part 63, subpart III) in 1998, we estimated that there were 78 slabstock foam facilities in the U.S. and 228 molded foam production facilities. A recent estimate is that there are 36 rebond foam facilities.

The Flexible Polyurethane Foam Fabrication Operations area source category includes processes engaged in cutting, bonding, and/or laminating pieces of flexible polyurethane foam together or to other substrates. Typical bonding techniques include gluing, taping, and flame lamination.

Foam fabrication adhesive use operations may use methylene chloride-based adhesives to adhere pieces of foam together. Most foam fabrication adhesives are applied by workers using spray guns. It is typically performed in large open rooms, with work stations spaced along a conveyor which moves the pieces of foam to be glued together.

Loop slitter adhesive use is a specialized type of foam fabrication adhesive use. Loop slitters are equipment at slabstock foam production and fabrication facilities that are used to slice large foam buns into thin sheets. Adhesive is used to attach the ends of the foam buns to one another before they are mounted on the loop slitter. The amount of adhesive used for loop slitters is relatively low because the adhesive is not applied continuously, just once or twice per shift when the foam buns are loaded onto the loop slitter.

Flame lamination refers to the bonding of foam to other substrates (i.e., cloth, foam, plastic, and other materials) where the bonding agent is scorched or melted foam. Thin sheets of foam are passed under a flame which scorches the foam surface and makes it sticky. The tacky foam sheet is then applied to a foam or fabric substrate.

All slabstock foam production plants perform foam fabrication, but there are also independently operated foam fabrication facilities. There is no foam fabrication trade association, so we do not have a good estimate of the number of foam fabrication facilities in the U.S. Prior to the promulgation of subpart III, EPA estimated that there were loop slitters at 40 slabstock foam production

facilities in the U.S. and 21 flame lamination facilities.

B. What are the production processes and emissions points for flexible polyurethane foam production and fabrication?

Both the Flexible Polyurethane Foam Production and Flexible Polyurethane Fabrication Operations area source categories were listed for regulation due to emissions of the urban HAP methylene chloride. Historically, methylene chloride was the only urban HAP used at foam production and foam fabrication facilities. Slabstock foam production facilities used methylene chloride as an auxiliary blowing agent (ABA) to control the density and other properties of the foam as it expanded during the pouring process. Methylene chloride was also used as an equipment cleaner, in particular for mix heads. Currently, almost all slabstock foam producers have discontinued any use of methylene chloride. A small number of molded and rebond foam facilities previously used methylene chloride in mold release agents and some molded foam facilities used it as a mix-head cleaner.

Foam fabricators used methylene chloride-based adhesives to adhere pieces of foam to one another. Flame laminators have never used methylene chloride.

C. What are the proposed requirements for area sources?

1. Applicability and Compliance Dates

This proposed NESHAP applies to both new and existing flexible foam production and flexible foam fabrication plants that are area sources. The owner or operator of an existing source would be required to comply with the area source NESHAP by the date of publication of the final rule in the **Federal Register**. The owner or operator of a new source would be required to comply with the area source NESHAP by the date of publication of the final rule in the **Federal Register** or at startup, whichever is later.

2. Proposed Emission Standards

Table 1 of this preamble summarizes the various foam production and fabrication area sources covered by this proposed rule and the corresponding proposed regulatory strategies. As shown in Table 1 of this preamble, slabstock foam producers may still use limited amounts of methylene chloride as an auxiliary blowing agent. The technologies determined to be GACT for this industry significantly reduce, but do not always eliminate the use of methylene chloride as an auxiliary blowing agent. Methylene chloride use is prohibited for other uses at foam production and foam fabrication facilities.

TABLE 1.—FOAM PRODUCTION AND FABRICATION PROCESSES AND CORRESPONDING PROPOSED REGULATIONS

Area source types	Proposed regulation
1. Slabstock polyurethane foam production.	a. Emission limits for methylene chloride used as an auxiliary blowing agent (ABA); b. Controls on storage vessels; c. Management practices for equipment leaks; and d. Prohibition on use of methylene chloride as an equipment cleaner. OR Eliminate use of methylene chloride in slabstock foam production processes.
2. Molded polyurethane foam production.	Prohibit use of methylene chloride as mold release agent or equipment cleaner.
3. Rebond foam production	Prohibit use of methylene chloride as mold release agent.
4. Foam fabrication adhesive use ..	Prohibit use of methylene chloride adhesives.

For slabstock foam production area sources, we are proposing emissions limits and management practices to reduce methylene chloride emissions from the production line, storage tanks, leaking equipment, and equipment cleaning. Emissions limits for methylene chloride used as an ABA are based on a formula which varies depending on the grades of foam being produced. Vapor balance systems or carbon beds would be required for methylene chloride storage vessels. The proposed management practices require plants to identify and correct leaking pumps and other equipment in methylene chloride service. Specifically, owners or operators would check periodically for equipment leaks (from quarterly for pumps and valves to annual for connectors) using EPA Method 21 (40 CFR part 60, appendix A). Leaks, which are defined as a reading of 10,000 parts per million (ppm) or greater, must be corrected within 15 days of when they are detected. The use of methylene chloride to clean mix heads and other equipment would be prohibited.

Slabstock foam facilities that do not use any methylene chloride at the facility would not be subject to these emission limitations and management practices. Such facilities would only need to submit a one-time report.

This proposed rule prohibits the use of methylene chloride-based mold release agents at molded and rebond foam facilities, methylene chloride-based equipment cleaners at molded foam facilities, and methylene chloride-based adhesives for foam fabrication.

3. Compliance Requirements

Slabstock foam area sources continuing to use methylene chloride would be required to monitor the HAP added at slabstock production mixheads and the HAP contained in and added to HAP ABA storage tanks. Plants using carbon adsorber systems to control emissions from HAP ABA storage tanks would be required to monitor the HAP content of exhaust streams from outlet vents. Plants using a recovery device to reduce methylene chloride emissions would be required to comply with a recovered HAP ABA monitoring and recordkeeping program.

The owner or operator would be required to submit semiannual reports containing information on allowable and actual HAP ABA emissions, carbon adsorbers on storage tanks, and equipment leaks. Owners and operators would also be required to submit annual compliance certifications. Records would be required to demonstrate compliance, including a daily operating log of foam runs containing the grades of foam produced and related data, and records related to storage tanks and equipment leaks. This proposed NESHAP also includes a simpler facility-wide compliance option that only requires that the facility measure the total amount of methylene chloride used at the facility. Slabstock foam plants that do not use any methylene chloride would be required to submit a one-time certification as part of their notification of compliance status.

Molded foam, rebond foam, and foam fabrication facilities which operate loop slitters would be required to prepare, and keep on file, compliance certifications which certify that the facility is not using the prohibited methylene-chloride based products and will not use them in the future. The plants would also maintain records documenting that the products they are using for the specific purposes do not contain any methylene chloride. These can be records that would be kept in the absence of this proposed rule such as adhesive usage information and Material Safety Data Sheets. Foam fabrication plants which do not operate loop slitters would have no compliance certification or recordkeeping requirements.

The owner or operator of each slabstock foam affected source that continues to use methylene chloride and, therefore, would be subject to the methylene chloride emissions limits, would be required to comply with several requirements of the General Provisions in 40 CFR part 63, subpart A. However, because of the intermittent nature of the slabstock foam process, we are not proposing to require that affected sources comply with the requirements for SSM plans and reports in 40 CFR 63.6(e)(3).

D. What is our rationale for selecting the proposed standards for area sources?

1. Selection of Proposed Standards

When the NESHAP for major sources of polyurethane foam production in 40 CFR part 63, subpart III was promulgated in 1998, we estimated that there were 78 slabstock foam facilities, and that all of these facilities were major sources. The NESHAP requirements, along with the revisions to the Occupational Safety and Health Administration (OSHA) permissible exposure and short-term exposure limits for methylene chloride (63 FR 50711, September 22, 1998), caused slabstock foam facilities to investigate, evaluate, and install technologies to reduce or eliminate the use of methylene chloride as an ABA at their facilities. These technologies include alternative formulations to reduce the amount of methylene chloride ABA needed, alternative non-HAP ABAs (acetone, liquid carbon dioxide), controlled or variable pressure foaming, and forced cooling. Based on recent contacts with the industry, we have verified that every known slabstock facility has converted their process to utilize one of these technologies. In many cases, these changes were instituted prior to the compliance date for subpart III, making the facilities area sources. As these technologies have been universally applied to major and area source slabstock foam production facilities, we have no reason to believe that these emissions reduction technologies are infeasible or inappropriate for area sources. Consequently, we propose to conclude that emissions limitations based on the application of these technologies are generally available control technology (GACT) for new and existing area sources.

Because the installation and operation of several of these pollution prevention technologies have resulted in the near total elimination of the use of and emissions of methylene chloride at slabstock foam production facilities, we have included a provision in this proposed rule that allows slabstock facilities that do not use any methylene chloride to submit a one-time report certifying that they do not use, and will not use in the future, any methylene chloride. We included this provision to reduce the recordkeeping and reporting burden for these facilities.

We are also aware that methylene chloride usage has been eliminated at many molded foam and rebond foam production facilities. Therefore, we have no reason to believe that the use of non-methylene chloride mold release agents and cleaners at molded and rebond foam production facilities is infeasible or inappropriate for area sources. Therefore, we determined that a prohibition of methylene chloride mold release agents and cleaners at molded and rebond foam production facilities is GACT for new and existing sources. While we are not aware of any area source molded foam or rebond foam facility that is currently using methylene chloride-based mold release agents or cleaners, we believe that it is appropriate to propose a prohibition on the use of these products to ensure that no methylene chloride is emitted from these facilities in the future.[5]

The changes to the OSHA permissible exposure and short-term worker exposure limits for methylene chloride had an even more significant impact on the flexible polyurethane foam fabrication source category, as it made it infeasible to continue to use methylene chloride-based adhesives for most foam fabrication operations. Current information indicates that owners and operators of foam fabrication sources have eliminated the use of methylene chloride-based adhesives. (Additional details are provided in the background information for this industry in Docket ID No. EPA–HQ–OAR–2006–0897.) The most common alternatives being used are acetone-based and water-based adhesives. Therefore, we have no reason to believe that the use of non-methylene chloride-based adhesives for foam fabrication applications is infeasible or inappropriate for area sources as a generally available management practice. In addition, because of the nature of the adhesives application process described above, we are not aware of control technologies or management practices that could be employed to limit methylene chloride emissions in foam fabrication operations. Consequently, we are proposing that a prohibition of the use of adhesives containing methylene chloride is GACT for foam fabrication operations. We are requesting comments on this proposed prohibition.

Among other things, we are asking for comment on the availability of cost effective alternatives to methylene chloride adhesives. We are also requesting comments on whether and under what circumstances methylene chloride-based adhesives (e.g., in small specialty applications) are being used or might be used by the foam fabrication industry, and what quantities are or might be involved in such applications. We also request information on any control technologies or management practices used to limit emissions of methylene chloride in the application of the methylene chloride-based adhesives and any cost information associated with such control approaches.

2. Selection of Proposed Compliance Requirements

For slabstock foam production facilities that continue to use methylene chloride, we concluded that requirements for monitoring and recording the amount of methylene chloride used are sufficient to ensure compliance with the proposed emissions limitations.

For slabstock foam production facilities that have eliminated the use of methylene chloride and are exempt from the emissions limitations in this proposed rule, we are proposing to require that owners or operators submit a one-time notification certifying that they do not use any methylene chloride and will not use it in the future as their notification of compliance status report.

In order to demonstrate compliance with the prohibition of the use of methylene chloride based mold release agents and cleaners for molded and rebond processes, we are proposing to

[5] Flame lamination foam fabrication facilities have never used, and thus never emitted, any methylene chloride and were not included in the listed category. Therefore, this proposed rule does not contain any emissions limitations for flame lamination facilities.

require preparation of a compliance certification, signed by a responsible official and kept on file, indicating that the facility has ceased the use of these prohibited products. The plant owner or operator would be required to maintain adhesive usage records and Material Safety Data Sheets or other documentation to show that no methylene chloride-based products are being used.

Currently available information from the foam fabrication industry and adhesive manufacturers suggests that it is not possible for typical foam fabrication operations to use methylene chloride-based adhesives and comply with OSHA permissible exposure and short-term worker exposure limits for methylene chloride. Because we assume that compliance with these OSHA standards is being achieved through the elimination of the use of methylene chloride-based adhesives, we do not believe that additional reporting or recordkeeping is necessary to demonstrate compliance with the proposed prohibition of the use of methylene-chloride based adhesives. Therefore, this proposed rule contains no compliance requirements for most foam fabrication affected sources.

However, unlike typical foam fabrication applications, we believe it may be possible for loop slitters to use methylenechloride— based adhesives and still comply with the OSHA worker exposure limits. This is because loop slitter adhesive application is brief and intermittent, typically not occurring more than once during a single shift. As a result, worker exposure is also brief and intermittent. Thus, it is possible that some loop slitter facilities could meet the OSHA time-weighted average exposure limitation without changing any of their normal procedures. Additionally, we believe that if compliance with the OSHA requirements could not be achieved without changing normal operating procedures, there are feasible measures that could be implemented to achieve compliance. For instance, the loop slitter adhesive could be applied by workers wearing respiration equipment, or a hood or other ventilation equipment could be added to the adhesive application station. Because of these possibilities, loop slitter operations using methylene chloride adhesives have the potential to meet the worker exposure limits set by OSHA, but still use and emit methylene chloride.

Due to this possibility, we are proposing to require that flexible polyurethane foam fabrication affected sources operating loop slitters prepare and keep on file a compliance certification, signed by a responsible official, indicating that the facility does not use any methylene chloride and will not use it in the future.

We are not proposing to apply the SSM requirements in 40 CFR 63.6(e)(3) to flexible polyurethane foam production and fabrication area sources. For slabstock facilities that elect not to use any methylene chloride, and for molded facilities, rebond facilities, and loop slitters that are prohibited from using methylene chloride-based products, SSM periods will have no impact on methylene chloride emissions.

There are also fundamental problems in applying the General Provision requirements for SSM to slabstock foam production facilities that continue to use methylene chloride. The rationale for not subjecting area source slabstock foam plants to the SSM requirements was laid out at promulgation of subpart III, which exempted major sources from these provisions.

The fundamental problem in applying the General Provisions SSM provisions to flexible polyurethane foam production facilities is defining a startup and a shutdown. The foam production process is intermittent in nature and, based on the EPA's knowledge of the industry, every foam production process will undergo at least one routine ''startup'' and one routine ''shutdown'' per day. The EPA never intended that these routine activities be addressed by the SSM requirements.

The intent of the SSM plan is to identify methods to reduce excess emissions that occur during these events when air pollution is emitted in quantities greater than the standard allows. Given the comprehensive approach of the adopted sections of subpart III to regulate emissions by restricting the amount of HAP used, EPA does not believe that, for foam production facilities, periods of SSM provide the opportunity for emissions not already anticipated.

VII. Proposed Area Source NESHAP for Lead Acid Battery Manufacturing

A. What area source category is affected by the proposed NESHAP?

The Lead Acid Battery Manufacturing area source category includes plants that manufacture batteries from lead, lead oxide paste, and sulfuric acid. These may be either of two types of batteries: (1) Starting, lighting, and ignition (SLI) batteries primarily used in automobiles, or (2) industrial and traction batteries. Industrial batteries include those used for uninterruptible power supplies and traction batteries are used to power electric vehicles such as forklifts.

We estimate that there are approximately 58 lead acid battery manufacturing area sources operating in the U.S. Many of these area sources are subject to the NSPS for lead acid battery manufacturing plants in 40 CFR part 60, subpart KK. Subpart KK applies to all lead acid battery manufacturing plants constructed or modified since 1982 if they produce or have the design capacity to produce in one day batteries containing an amount of lead equal to or greater than 5.9 megagrams (6.5 tons).

B. What are the production processes and emissions points at facilities that manufacture lead acid batteries?

The lead acid battery manufacturing process includes preparing battery grids through stamping or casting lead. Lead oxide paste is added to the grids in the grid pasting operation creating plates that are cured and assembled into a battery. Batteries are then charged using sulfuric acid in the forming operations. Lead oxide may be prepared by the battery manufacturer, as is the case for many larger battery manufacturing plants, or may be purchased from a supplier.

The lead acid battery manufacturing area source category was listed for regulation due to emissions of the urban HAP lead, which is used as a primary component of a battery. Cadmium, another urban HAP emitted in trace amounts, was also identified in the listing of the lead acid battery manufacturing area source category. Cadmium and other trace urban HAP metals that are emitted by lead acid battery manufacturing plants (arsenic, beryllium, chromium, manganese, and nickel) are controlled by the same devices that control lead emissions.

C. What are the proposed requirements for area sources?

1. Applicability and Compliance Dates

The proposed NESHAP apply to both new and existing lead acid battery manufacturing plants that are area sources. We are not aware of any major source lead acid battery manufacturing plants. We are proposing that owners or operators of existing sources comply with all the requirements of the area source NESHAP no later than 1 year after the date of publication of the final rule in the **Federal Register**. The owner or operator of a new source would be required to comply with the area source NESHAP on the date of publication of the final rule in the **Federal Register** or at startup, whichever is later.

2. Proposed Emissions Standards

We are proposing to adopt as the NESHAP for the lead acid battery manufacturing area source category the numerical emissions limits for grid casting, paste mixing, three-process operation, lead oxide manufacturing, lead reclamation, and other lead emitting processes in 40 CFR 60.372 of the NSPS for lead acid batteries. These lead discharge limits are:

- 0.40 milligram of lead per dry standard cubic meter of exhaust (mg/m^3) from grid casting facilities,
- 1.00 mg/m^3 from paste mixing facilities,
- 1.00 mg/m^3 from three-process operations,
- 5.0 mg per kilogram of lead feed from lead oxide manufacturing facilities,
- 4.50 mg/m^3 from lead reclamation facilities, and
- 1.0 mg/m^3 from any other lead-emitting operations.

We are also proposing to adopt as the NESHAP for the lead acid battery manufacturing area source category the opacity limits from the lead acid battery NSPS. The opacity must be no greater than 5 percent from lead reclamation facilities and no greater than 0 percent from any affected facility except lead reclamation facilities.

3. Compliance Requirements

We are proposing to include in this proposed NESHAP the monitoring, testing, recordkeeping, and reporting requirements in the NSPS for lead acid batteries. This proposed NESHAP requires controls for lead emissions from the paste mixing, three-process operation, lead oxide manufacturing, grid casting, lead reclamation processes, and other lead-emitting processes. The owner or operator would be required to submit quarterly reports containing information on emissions that exceed the applicable limits. Records would be required to demonstrate compliance. We are also proposing to adopt the testing, monitoring, recordkeeping, and reporting requirements in the part 60 General Provisions (40 CFR part 60, subpart A) and the initial notification and notification of compliance requirements in the part 63 General Provisions (40 CFR part 63, subpart A). We have explicitly identified in the proposed NESHAP the applicable General Provisions of both 40 CFR parts 60 and 63.

The proposed NESHAP allows existing plants to utilize previously conducted performance tests, when they are representative of current conditions, to demonstrate compliance. Plants without representative prior performance tests are required to conduct performance tests by 180 days after the compliance date.

D. What is our rationale for selecting the proposed standards for area sources?

1. Selection of Proposed Standards

The NSPS applies to all lead acid battery manufacturing plants constructed or modified since 1982 if they produce or have the design capacity to produce in one day batteries containing an amount of lead equal to or greater than 5.9 megagrams (6.5 tons). Many existing lead acid battery facilities are subject to the NSPS and use fabric filters and impingement scrubbers to meet the lead emissions limits in the NSPS. In addition, through discussions with the industry trade organization, we have concluded that the existing facilities, whether they are subject to the NSPS or not, have installed fabric filters or other control devices that will allow them to meet the standard.

Therefore, we have no reason to believe that the conventional control techniques employed to meet the emissions limits in the NSPS are infeasible or inappropriate for new or existing area sources. We have determined that the emissions control requirements in the NSPS for lead acid battery manufacturing are GACT for new and existing sources in the lead acid battery manufacturing area source category.

2. Selection of Proposed Compliance Requirements

We have reviewed the compliance requirements in the NSPS for lead acid batteries and the NSPS General Provisions (40 CFR part 60, subpart A) applicable to this proposed NESHAP and concluded that these requirements are sufficient to ensure compliance with the proposed emissions limit standards. Therefore, we are proposing to adopt the NSPS testing, monitoring, and recordkeeping requirements in this proposed rule.

The part 60 General Provisions are necessary for effective application of the lead acid battery NSPS and are therefore incorporated into this proposed rule as well. We are also incorporating certain provisions in the NESHAP General Provisions (40 CFR part 63, subpart A) to address aspects of this proposed rule not covered by the part 60 General Provisions.

VIII. Proposed Area Source NESHAP for Wood Preserving

A. What area source category is affected by the proposed NESHAP?

The Wood Preserving area source category includes facilities that use pressure or thermal processes to impregnate chemicals into wood to a depth that will provide effective long-term resistance to attack by fungi, bacteria, insects, and marine borers. As most sources in this source category are minor sources, few are subject to State air emissions regulations or permit requirements.

Existing facilities in the wood preserving source category are currently well controlled in terms of emissions of the urban HAP metals chromium and arsenic as a result of a voluntary decision by the industry to discontinue certain specified uses of chromated copper arsenate (CCA). The discontinued uses include dimensional lumber and wood used in play structures, decks, picnic tables, landscaping timbers, residential fencing, patios, walkways, and boardwalks. The voluntary agreement has reduced the usage and emissions of arsenic and chromium compounds from CCA treatment facilities by more than 80 percent. On March 17, 2003, pursuant to section 6(f)(1) of the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), a cancellation order was signed in response to the use terminations and cancellations voluntarily requested by the registrants of wood preservative pesticide products containing CCA). Under the cancellation order, as of December 31, 2003, newly produced CCA may only be used for preservative treatment of a limited number of use categories of forest products (e.g., lumber and timber for marine construction for salt water use; wood for highway construction; piles; poles; agricultural posts; and treated wood used as structural members on farms). The use of CCA has been effectively eliminated from household commodities such as decking as a result of the FIFRA cancellation order. Household commodities such as decking are now generally treated with waterborne copper-based wood preservative systems known as ammoniacal copper quat (ACQ) or copper azole (CA). These preservatives do not contain arsenic or chromium, or any other urban HAP as active ingredients. (See Docket Item 0001 ''Background on the Wood Preserving Industry'' in Docket ID No. EPA–HQ–OAR–2006–0897.)

With regard to dioxin emissions, pursuant to FIFRA, EPA issued a notice

on the wood preservative uses of pentachlorophenol to establish reliable and enforceable methods for implementing certified limits for hexachlorodibenzo-p-dioxin (HxCDD) and 2,3,7,8-tetrachlorodibenzo-p-dioxin (2,3,7,8–TCDD or dioxin) (52 FR 140, January 2, 1987). Per the EPA notice, levels of 2,3,7,8–TCDD are not allowed to exceed 1 part per billion (ppb) in any product, and any manufacturing-use pentachlorophenol has to have HxCDD levels below an average of 2 ppm over a monthly release or a batch level limit of 4 ppm. The pentachlorophenol registrant has to submit monthly analyses to EPA to demonstrate compliance with these requirements.

Industry representatives have reported there is no current use of methylene chloride by the wood preserving industry. In 1992, its use as a solvent system was removed from the standards of the American Wood Preservers' Association, which govern the treatment of wood products.

All wood preserving plants currently in operation are area sources. We estimate that there are approximately 393 wood preserving area sources operating in the U.S. and expect that new facilities will be built in the coming years. In this rule, we are proposing standards for both new and existing area sources.

B. What are the production processes and emissions points at wood preserving facilities?

Wood preserving or treatment is accomplished by either pressure or thermal processes. To initiate either process, wood products are debarked, sawed, and conditioned. More than 95 percent of all treated wood is preserved through pressurized processes. These processes are performed inside an enclosed vessel and involve the application of pneumatic or hydrostatic pressure to expedite the movement of preservative liquid into the wood.

In a thermal treatment process, the wood is exposed to the preservative in an open vessel. The thermal process involves exposing wood to a heated preservative for 6 to 12 hours followed by exposure to the preservative at ambient temperature for 2 to 4 hours. According to industry representatives, there are currently only three facilities using the thermal process to treat the bottom portion (i.e., the 6 to 8 feet that will be below ground) on certain types of utility poles.

There are two general classes of wood preservatives: oils, such as creosote and petroleum solutions of pentachlorophenol (also called ''penta'' or ''PCP'') and copper naphthanate, and waterborne salts that are applied as water solutions. Treated wood is used throughout the U.S. in a variety of capacities, including utility poles, lumber and timber, railroad ties, fence posts, marine pilings, plywood, and other miscellaneous products. By extending the service life of available wood through treatment with chemicals, wood treatment reduces the demands on forestry resources, reduces operating costs in industries such as utilities and railroads, and helps ensure safe working conditions where timbers are used as support structures.

The urban HAP emitted from wood preserving operations that were the basis for the source category listing are arsenic, chromium, methylene chloride, and dioxins. These HAP may be released from the treatment process or an opening or leak in the process equipment. Significant effort is made by the industry to minimize any excess preservative that might contribute to emissions because the preservative can be as much as one-third of the total product cost. As a result, almost all wood preservation employing a pressure process takes place in a closed retort. A retort is an airtight pressure vessel, typically a long horizontal cylinder, used for the pressure impregnation of wood products with a liquid wood preservative. Proper use of a retort or similar vessel minimizes the loss of excess preservative and thereby limits HAP emissions.

All of the thermal treatment processes that have been identified by industry utilize air scavenging systems to capture and control emissions coming from the process treatment vessel during the treatment process.

After the preservative has been impregnated in the wood, the treated wood is set out to dry over a drip pad to collect preservative not absorbed during the treatment process. Regulations promulgated pursuant to the Resource Conservation and Recovery Act prohibit the presence of any free preservative drippage from products after they leave the process drip pad.

C. What are the proposed requirements for area sources?

1. Applicability and Compliance Dates

The proposed NESHAP apply to both new and existing wood preserving plants that are area sources. Because existing area sources are already complying with the proposed standards, we are proposing that owners or operators of existing sources comply with all the requirements of the area source NESHAP by the date of publication of the final rule in the **Federal Register**. The owner or operator of a new source would be required to comply with the area source NESHAP by the date of publication of the final rule in the **Federal Register** or at startup, whichever is later.

2. Proposed Standards

We are proposing to adopt as the NESHAP for the Wood Preserving area source category the control technologies and management practices currently used by most facilities within the wood preserving industry. Facilities using a pressure treatment process would be required to use a retort or similarly enclosed vessel for the preservative treatment of wood involving any wood preservatives containing chromium, arsenic, dioxins, or methylene chloride. Facilities using a thermal treatment process involving any wood preservatives containing chromium, arsenic, dioxins, or methylene chloride would be required to use process treatment tanks equipped with air scavenging systems to capture and control air emissions.

These proposed standards would also require facility operators to minimize emissions from process tanks and equipment (e.g., retorts, other enclosed vessels, and thermal treatment tanks), as well as storage, handling, and transfer operations. These standards would have to be documented in a management practices plan that must include, but not be limited to, the following activities:

- Minimizing preservative usage;
- Maintaining records on the type of treatment process and types and amounts of wood preservatives used at the facility;
- For the pressure treatment process, maintaining charge records identifying pressure reading(s) inside the retorts (or similarly enclosed vessels, if applicable);
- For the thermal treatment process, maintaining records that an air scavenging system is installed and operated properly during the treatment process;
- For the pressure treatment process, fully draining the retort prior to opening the retort door;
- Storing treated wood product on drip pads or in a primary containment area to convey preservative drippage to a collection system until drippage has ceased;
- Promptly collecting any spills; and
- Performing relevant corrective actions or preventative measures in the event of a malfunction before resuming operations.

Existing written standard operating procedures may be used as the

management practices plan if those procedures include the minimum activities required for a management practices plan.

3. Compliance Requirements

Plants would be required to comply with limited notification requirements in the part 63 General Provisions (40 CFR part 63, subpart A). This proposed rule establishes the content and deadlines for submission of the notifications. We have explicitly identified in the proposed NESHAP the applicable General Provisions of 40 CFR part 63.

D. What is our rationale for selecting the proposed standards for area sources?

1. Selection of Proposed Standards

Over the past 15 years, the wood preserving industry has undergone several changes related to the types of preservatives used for certain applications and the associated emissions with wood preservatives. Prior to 2003, much of the urban HAP metal emissions from the wood preservation area source category came from the preservative treatment of wood using CCA.

In determining GACT for the wood preserving source category, we identified different management practices and control technologies used to reduce air emissions from pressure treatment processes and thermal treatment processes. Under section 112(d)(1) of the CAA, EPA may ''distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards * * *.'' There are basic differences between the two treatment processes in the type of process vessel used, the mechanisms affecting the potential generation of air emissions (pressure versus thermal), and the way emissions are controlled. Consequently, we are proposing a GACT standard for the pressure treatment subcategory and a GACT standard for the thermal treatment subcategory.

For wood treatment facilities using pressure treatment processes, any metal HAP that are included as part of the wood preservative formulation (such as CCA) are impregnated into the wood product inside a pressurized vessel (retort), and, therefore, significant air emissions do not occur during the process. After the retort is returned to ambient pressure, excess preservative is drained back into the storage tanks and the treated product is stored on drip pads prior to shipment. Metal HAP are normally released into the environment as PM and will not enter the air during the drying process. As demonstrated by the 2004 TRI for this industry, nationwide air emissions of all metal HAP are negligible (i.e., arsenic = 0.0002 pounds and chromium compounds = 0.0003 pounds). We have not identified any other management practices or control technologies that would provide additional emissions reductions in a cost effective manner. Therefore, GACT for pressure treatment processes is the management practices described above that are being used to minimize emissions from the process equipment and manufacturing operations.

The same type of retort process used in the application of CCA is used for most wood preservatives containing pentachlorophenol and emissions of dioxin are likewise limited as a result. Dioxin also has a very low vapor pressure, making it less likely to volatilize into the air during the drying process. In fact, the 2004 TRI shows less than 0.005 grams of dioxin reported nationwide for the wood preserving industry. We have not identified any other management practices or control technologies that would provide additional emissions reductions in a cost effective manner for facilities using pressure treatment processes. Therefore, the management practices that are being used to minimize emissions from the retort or other similarly enclosed process equipment associated with the pressure treatment processes are GACT.

For wood treatment facilities using thermal processes, the wood product is placed inside a treatment tank that may contain wood preservative with one of the urban HAP for which this category was listed. At the three existing facilities using the thermal process, air emissions are captured and controlled by an air scavenging system, which consists of a capture system (e.g., skirting around the tank) vented to a vapor recovery tank that collects condensate from the vapors. Therefore, no significant air emissions occur during the thermal treatment process.

We have not identified any other management practices or control technologies that would provide additional emissions reductions in a cost effective manner for thermal treatment processes. Therefore, GACT for thermal treatment facilities entails using air scavenging systems to control emissions from the process treatment tanks associated with thermal processes consistent with the practices described above.

Industry representatives also informed us that methylene chloride was replaced in their processes several years ago with different solvent carriers. The use of methylene chloride as a solvent system was removed from the standards of the American Wood Preservers' Association in 1992. (See Docket Item 2006–0897–0001, ''Background on the Wood Preserving Industry'' in Docket ID No. EPA–HQ–OAR–2006–0897.) There have been no emissions of methylene chloride reported in the TRI for the industry since 1992. However, because we cannot be certain that a new use for methylene chloride will not be developed in the future, we are proposing to require the same standards for a preservative containing methylene chloride.

Based on our evaluation of the industry emissions and not being able to identify other cost effective management practices or control technologies that would provide additional emissions reductions involving chromium, arsenic, dioxins, or methylene chloride, we are proposing to establish standards based on current management practices and control technologies to minimize air emissions.

2. Selection of Proposed Compliance Requirements

The proposed standards require a minimal level of monitoring and recordkeeping to demonstrate compliance. For this reason, we are proposing to base the compliance requirements for new and existing area sources on certain notification requirements in the part 63 General Provisions. The initial notification of applicability required by 40 CFR 63.9(b)(2) would require the owner or operator to identify the plant as an area source subject to the standards. The notification of compliance status would require the owner or operator to certify compliance with the standards. No other recordkeeping or reporting requirements in the General Provisions would apply.

IX. Proposed Exemption of Certain Area Source Categories From Title V Permitting Requirements

Section 502(a) of the CAA provides that EPA may exempt one or more area sources from the requirements of title V if EPA finds that compliance with such requirements is ''impracticable, infeasible, or unnecessarily burdensome'' on such area sources. EPA must determine whether to exempt an area source from title V at the time we issue the relevant section 112 standard (40 CFR 70.3(b)(2)). We are proposing in this action to exempt acrylic and modacrylic fibers production, flexible polyurethane foam production and fabrication, lead acid battery manufacturing, and wood preserving

area source categories from the requirements of title V. These area source categories would not be required to obtain title V permits solely as a function of being the subject of the proposed NESHAP; however, if they were otherwise required to obtain title V permits, such requirement(s) would not be affected by the proposed exemption.

Consistent with the statute, EPA has found that compliance with title V permitting is ''unnecessarily burdensome'' for acrylic and modacrylic fibers production, flexible polyurethane foam production and fabrication, lead acid battery manufacturing, and wood preserving area sources. EPA's inquiry into whether this criterion was satisfied was based primarily upon consideration of the following four factors: (1) Whether title V would result in significant improvements to the compliance requirements that we are proposing for these area source categories; (2) whether title V permitting would impose a significant burden on these area sources and whether that burden would be aggravated by any difficulty these sources may have in obtaining assistance from permitting agencies; (3) whether the costs of title V permitting for these area sources would be justified, taking into consideration any potential gains in compliance likely to occur for such sources; and (4) whether there are implementation and enforcement programs in place that are sufficient to assure compliance with these NESHAP without relying on title V permits.

EPA also considered, consistent with the guidance provided by the legislative history of CAA section 502(a),[6] whether exempting area source categories would adversely affect public health, welfare or the environment. We have considered the factors above in determining whether to include an exemption from title V in the proposed NESHAP for acrylic and modacrylic fibers production, flexible polyurethane foam production and fabrication, lead acid battery manufacturing, and wood preserving area sources.

The first factor is whether title V would result in significant improvements to the compliance requirements we are proposing for these area source categories. We looked at the compliance requirements of the proposed NESHAP to see if they were substantially equivalent to the monitoring, recordkeeping and reporting requirements of title V (see 40 CFR 70.6 and 71.6) that we believe are important for assuring compliance with the NESHAP. The purpose of this review was to determine if title V is ''unnecessary'' to improve compliance with these NESHAP. A finding that title V would not result in significant improvements to the compliance requirements in the proposed NESHAP would support a conclusion that title V permitting is ''unnecessary'' for area sources in these categories. One way that title V may improve compliance is by requiring monitoring (including recordkeeping designed to serve as monitoring) to assure compliance with the emissions limitations and control technology requirements imposed in the standard. The authority for adding new monitoring in the permit is in the ''periodic monitoring'' provisions of 40 CFR 70.6(a)(3)(i)(B) and 40 CFR 71.6(a)(3)(i)(B), which allow new monitoring to be added to the permit when the underlying standard does not already require ''periodic testing or instrumental or noninstrumental monitoring (which may consist of recordkeeping designed to serve as monitoring).'' In addition, title V imposes a number of recordkeeping and reporting requirements that may be important for assuring compliance. These include requirements for a monitoring report at least every 6 months, prompt reports of deviations, and an annual compliance certification. See 40 CFR 70.6(a)(3) and 40 CFR 71.6(a)(3), 40 CFR 70.6(c)(1) and 40 CFR 71.6(c)(1), and 40 CFR 70.6(c)(5) and 40 CFR 71.6(c)(5).

We examined the first factor for each of the source categories and determined that a title V permit would not result in significant improvements to the compliance requirements that we are proposing. The following paragraphs discuss each source category separately. To determine whether title V permits would add significant compliance requirements for the Acrylic and Modacrylic Fibers Production area source category, we compared the title V monitoring, recordkeeping, and reporting requirements mentioned above to those requirements in the proposed NESHAP, which adopts the compliance requirements in the State-issued permit for the one area source plant currently in operation. The proposed NESHAP requires CPMS to measure and record the water flow rate to the control device (wet scrubber) every 15 minutes and to determine the daily average flow rate. Periodic visual inspections of AN storage tanks equipped with a fixed roof in combination with an internal floating roof must be conducted according to the NSPS requirements in 40 CFR part 60, subpart Kb. Because both the continuous and noncontinuous monitoring methods required by the proposed NESHAP would provide periodic monitoring, title V would not add any monitoring to the proposed NESHAP.

We also considered the extent to which title V could enhance compliance through recordkeeping or reporting requirements, including title V requirements for a 6-month monitoring report, deviation reports, and an annual compliance certification in 40 CFR 70.6 and 71.6. The proposed NESHAP for acrylic and modacrylic fibers production requires the plant to determine compliance with daily average operating limits for the water flow rates to each control device on a monthly basis and to submit compliance reports to EPA or the delegated authority on a quarterly basis. Should the daily average water flow rate to a wet scrubber control device fall below the operating limits, the plant must notify EPA or the delegated authority in writing within 10 days of the identification of the exceedance. All area source plants would be required to comply with the requirements for startup, shutdown, and malfunction plans, reports, and records in 40 CFR 63.6(e)(3).

Records are required to demonstrate compliance with the NSPS inspection and repair requirements for storage tanks in 40 CFR part 60, subpart Kb. The information required in the proposed NESHAP is similar to the information that must be provided in the deviation reports and semiannual monitoring reports required under 40 CFR 70.6(a)(3) and 40 CFR 71.6(a)(3).

The proposed NESHAP does not require an annual compliance certification report, which is a requirement of a title V permit. See 40 CFR 70.5(c)(9)(iii) and 40 CFR 71.6(c)(5)(i). EPA believes that the annual certification reporting requirement is not necessary because the quarterly reports are adequate to ensure compliance for existing sources. New sources would submit notifications and reports required by the part 63 General Provisions.

The monitoring, recordkeeping and reporting requirements in the proposed NESHAP for the Acrylic and Modacrylic Fibers Production area source category are substantially equivalent to such requirements under title V. Therefore,

[6] The legislative history of section 502(a) of the Clean Air Act suggests that EPA should not grant title V exemptions where doing so would adversely affect public health, welfare, or the environment. (See Chafee-Baucus Statement of Senate Managers, Environment and Natural Resources Policy Division 1990 CAA Leg. Hist. 905, compiled November 1993.)

we conclude that title V would not result in significant improvements to the compliance requirements we are proposing for this area source category.

To determine whether title V permits would add significant compliance requirements to the proposed NESHAP for Lead Acid Battery Manufacturing, we also compared the title V monitoring, recordkeeping, and reporting requirements to those requirements in the proposed NESHAP, which adopts the compliance requirements in the NSPS. The NSPS requires that a facility using a scrubbing system install, calibrate, maintain, and operate a monitoring device that measures and records the pressure drop across the scrubbing system at least once every 15 minutes. Each facility must demonstrate compliance by either conducting a performance test or submitting the results of a previous performance test conducted using the methods and procedures in the proposed NESHAP. Because both the continuous and noncontinuous monitoring methods required by the proposed NESHAP would provide periodic monitoring, title V would not add any monitoring to the proposed NESHAP.

We also considered the extent to which title V could enhance compliance through recordkeeping or reporting requirements, including title V requirements for a 6-month monitoring report, deviation reports, and an annual compliance certification in 40 CFR 70.6 and 71.6. Records are required to demonstrate compliance. Plants also would be required to comply with the testing, monitoring, recordkeeping, and reporting requirements in the part 60 General Provisions (40 CFR part 60, subpart A). The information required in the proposed NESHAP is similar to the information that must be provided in the deviation reports and semiannual monitoring reports required under 40 CFR 70.6(a)(3) and 40 CFR 71.6(a)(3).

The proposed NESHAP does not require an annual compliance certification report, which is a requirement of a title V permit. See 40 CFR 70.5(c)(9)(iii) and 40 CFR 71.6(c)(5)(i). EPA believes that the annual certification reporting requirement is not necessary because the quarterly reports are adequate to ensure compliance for new and existing sources.

The monitoring, recordkeeping and reporting requirements in the proposed NESHAP for the Lead Acid Battery Manufacturing area source category are substantially equivalent to such requirements under title V. Therefore, we conclude that title V would not result in significant improvements to the compliance requirements we are proposing for this area source category.

To determine whether title V permits would add significant compliance requirements, we also compared the title V monitoring, recordkeeping, and reporting requirements to those requirements in the proposed NESHAP for Flexible Polyurethane Foam Production and Fabrication area source category. The proposed NESHAP does not contain monitoring or periodic reporting requirements for facilities that have already reduced HAP emissions by complying with the proposed ban on methylene chloride. These provisions are not included in the proposed NESHAP for this area source category because the discontinued use of methylene chloride would reduce urban HAP emissions without the need for continuous or periodic monitoring of equipment or operations. For slabstock foam plants still using methylene chloride, the proposed NESHAP requires the same monitoring that must be performed by major sources. Therefore, title V would not add any monitoring to the proposed NESHAP.

We also considered the extent to which title V could enhance compliance for area sources through recordkeeping or reporting requirements, including title V requirements for a 6-month monitoring report, deviation reports, and an annual compliance certification in 40 CFR 70.6 and 71.6. The proposed NESHAP requires foam plants that have discontinued the use of methylene chloride to certify compliance with the prohibition on methylene chloride. For slabstock foam plants still using methylene chloride, the proposed NESHAP requires the same recordkeeping or reporting that must be performed by major sources. The information required in the proposed reports and records is similar to the information that must be provided in the deviation reports and required under 40 CFR 70.6(a)(3) and 40 CFR 71.6(a)(3).

The proposed NESHAP requires a report if a deviation occurs, but does not require periodic compliance reports. The addition of periodic reports for sources that are not subject to monitoring requirements would not result in significant improvements to the compliance requirements we are proposing for this area source category.

The proposed NESHAP does not require an annual compliance certification report, which is a requirement of a title V permit. See 40 CFR 70.5(c)(9)(iii) and 40 CFR 71.6(c)(5)(i). EPA believes that the annual certification reporting requirement is not necessary because the deviation reports are adequate to ensure compliance for new and existing sources.

To determine whether title V permits would add significant compliance requirements, we also compared the title V monitoring, recordkeeping, and reporting requirements to those requirements in the proposed NESHAP for the Wood Preserving area source category. EPA determined that the good management practices currently used at most facilities during the application of wood preservatives is GACT for this source category. The rule proposes to require recordkeeping and deviation reporting to ensure compliance with the NESHAP. Given the nature of the management practices proposed for this source category, we believe that the recordkeeping and reporting requirements in the rule are sufficient to ensure compliance and find that additional monitoring is not necessary in this instance. The proposed NESHAP does not contain monitoring or periodic reporting requirements because the facilities have reduced HAP emissions by using good management practices as part of their standard method of operation.

The management practices would reduce urban HAP emissions without the need for continuous monitoring of equipment or operations. Therefore, title V would not add any monitoring to the proposed NESHAP. We also considered the extent to which title V could enhance compliance for area sources through recordkeeping or reporting requirements, including title V requirements for a 6-month monitoring report, deviation reports, and an annual compliance certification in 40 CFR 70.6 and 71.6.

The proposed NESHAP also requires wood preserving plants to certify compliance with the management practices identified as GACT. In addition, wood preserving plants must maintain records showing compliance with the required management practices in the proposed NESHAP and report deviations. The information required in the proposed reports and records is similar to the information that must be provided in the deviation reports and required under 40 CFR 70.6(a)(3) and 40 CFR 71.6(a)(3). We have determined that title V would not enhance compliance for area sources through additional recordkeeping or reporting requirements.

The second factor we considered is whether title V permitting would impose significant burdens on these area sources and whether that burden would be aggravated by any difficulty

these sources may have in obtaining assistance from permitting agencies. The information collection request (ICR) for parts 70 and 71 describes the title V burdens and costs in the aggregate, and although they do not focus on area sources, they do describe the various activities undertaken by title V sources, including area sources, so many of the same burdens and costs described in the ICR will also apply to area sources. Some examples of this burden include reading and understanding permit program guidance and regulations, completing the permit application, preparing and submitting applications for permit revisions every 5 years, and paying permit fees. We believe that this cost is a significant burden for these area sources.

The third factor we considered is whether the costs of title V permitting for these area sources would be justified, taking into consideration any potential gains in compliance likely to occur for such sources. Based on our consideration of factor 1 (described above) and factor 4 (described below), we did not identify potential gain in compliance from title V permitting. Therefore, we conclude that the costs of title V permitting for these area source categories are not justified.

The fourth factor we considered is whether there are implementation and enforcement programs in place that are sufficient to assure compliance with these NESHAP without relying on title V permits. A conclusion that these criteria can be met would support a conclusion that title V permitting is ''unnecessary'' for these area sources. See 70 FR 15254. There are State programs in place to enforce these area source NESHAP. We believe that these programs are sufficient to assure compliance with these NESHAP. In addition, EPA retains authority to enforce these NESHAP anytime under CAA sections 112, 113 and 114. In light of the above, we conclude that title V permitting is ''unnecessary'' to assure compliance with these NESHAP because the statutory requirements for implementation and enforcement of these NESHAP by the delegated States and EPA are sufficient to assure compliance with these area source NESHAP, in all parts of the U.S., without title V permits. In addition, small business assistance programs required by CAA section 507 may be used to assist area sources that have been exempted from title V permitting. Also, States and EPA often conduct voluntary compliance assistance, outreach, and education programs (compliance assistance programs), which are not required by statute. These additional programs supplement and enhance the success of compliance with these area source NESHAP. In light of all of the above, we conclude that there are implementation and enforcement programs in place that are sufficient to assure compliance with these NESHAP without relying on title V permitting.

In addition to evaluating whether compliance with title V requirements is ''unnecessarily burdensome'', EPA also considered, consistent with guidance provided by the legislative history of section 502(a), whether exempting these area source categories from title V requirements would adversely affect public health, welfare, or the environment. Exemption of these area source categories from title V requirements would not adversely affect public health, welfare, or the environment because the level of control would remain the same if a permit were required. Therefore, we conclude that exempting these area sources from title V permitting requirements in these proposed rules would not adversely affect public health, welfare, or the environment.

One of the primary purposes of the title V permitting program is to clarify, in a single document, the various and sometimes complex regulations that apply to sources in order to improve understanding of these requirements and to help sources to achieve compliance with the requirements. In this case, however, we do not believe that a title V permit is necessary for us to understand the requirements applicable to these area sources. This proposal would add new requirements to the NESHAP for new area sources. We have determined that the current requirements for existing area sources reflect GACT and thus adopted them in the proposed rules for existing sources. Furthermore, we do not find the requirements for existing sources to be very complicated to understand or implement. For these reasons, we do not find that title V permitting is necessary to improve understanding of and achieve compliance with these standards.

Based on the above analysis, we conclude that title V permitting would be ''unnecessarily burdensome'' for the acrylic and modacrylic fibers production, flexible polyurethane foam production and fabrication, lead acid battery manufacturing, and wood preserving area source categories. We are, therefore, proposing that these area source categories be exempt from title V permitting requirements.

X. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a ''significant regulatory action'' because it may raise novel legal or policy issues. Accordingly, EPA submitted this action to OMB for review under Executive Order 12866, and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

The information requirements in the proposed NESHAP for Acrylic and Modacrylic Fibers Production Area Sources, Carbon Black Production Area Sources, Chemical Manufacturing: Chromium Compounds Area Sources, Flexible Polyurethane Foam Production and Fabrication Area Sources, Lead Acid Battery Manufacturing Area Sources, and Wood Preserving Area Sources have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The ICR document prepared by EPA has been assigned EPA ICR number 2256.01.

The recordkeeping and reporting requirements in the proposed rules are based on the existing permit requirements as well as the information collection requirements in the part 63 General Provisions (40 CFR part 63, subpart A). The recordkeeping and reporting requirements in the General Provisions are mandatory pursuant to section 114 of the CAA (42 U.S.C. 7414). All information submitted to EPA pursuant to the information collection requirements for which a claim of confidentiality is made is safeguarded according to CAA section 114(c) and the Agency's implementing regulations at 40 CFR part 2, subpart B.

The proposed information collection requirements for acrylic and modacrylic fibers production are the same as the requirements that are in the current State operating permit for the one existing source. The only new information collection requirements that would apply to this area source would consist of initial notifications and an SSM plan. Any new acrylic and modacrylic fibers production area source would be subject to all information collection requirements in the part 63 General Provisions.

The annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 9 labor hours per year at a cost of $780 for the one existing acrylic and modacrylic fibers area source. No

capital/startup costs or operation and maintenance costs are associated with the proposed requirements. No costs or burden hours are estimated for new acrylic and modacrylic fibers production area sources because no new area sources are estimated during the next 3 years.

The proposed NESHAP for carbon black production area sources includes testing, monitoring, recordkeeping, and reporting requirements equivalent to current requirements applicable to the existing area source carbon black production facility. The only new information collection requirements that would apply to this area source would consist of initial notifications and SSM plans. Any new carbon black production area source would be subject to all information collection requirements in the part 63 General Provisions.

The annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 9 labor hours per year at a cost of $780 for the one existing carbon black production area source. No capital/startup costs or operation and maintenance costs are associated with the proposed requirements. No costs or burden hours are estimated for new carbon black production area sources because no new sources are estimated during the next 3 years.

The proposed PM testing, monitoring, recordkeeping, and reporting requirements for existing chromium compounds manufacturing area sources are the same as the requirements that are in the current title V operating permit for the two existing facilities. The only new information collection requirements that would apply to these area sources would consist of initial notifications, SSM plans, and control device inspections at one plant. Any new chromium compounds manufacturing area source would be subject to all information collection requirements in the part 63 General Provisions.

The annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 194 labor hours per year at a cost of $16,409 for the two existing chromium compounds manufacturing area sources. No capital/startup costs or operation and maintenance costs are associated with the proposed requirements. No costs or burden hours are estimated for new chromium compounds manufacturing area sources because no new area sources are estimated during the next 3 years.

The proposed NESHAP for flexible polyurethane foam production and fabrication operations area sources requires a one-time notification by slab stock foam facilities that they do not use methylene chloride and records documenting that they do not use methylene chloride. One plant that uses methylene chloride would be subject to additional reporting requirements.

The annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 835 labor hours per year at a cost of $70,686 for the 500 or more existing flexible foam fabrication and production area sources. No capital/startup costs or operation and maintenance costs are associated with the proposed requirements. No costs or burden hours are estimated for new flexible foam production or fabrication area sources because no new sources are estimated during the next 3 years.

The proposed PM testing, monitoring, recordkeeping, and reporting requirements for new and existing lead acid battery manufacturing area sources are the same as the requirements that are in the NSPS (40 CFR part 60, subpart KK). In addition, new information collection requirements that would apply to these area sources would consist of either an initial performance test or submission of the results of a previous performance test and the requirements in the part 63 General Provisions for initial notifications.

The annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 675 labor hours per year at a cost of $57,147 for the 58 existing lead acid battery manufacturing area sources. No capital/startup costs or operation and maintenance costs are associated with the proposed requirements. No costs or burden hours are estimated for new lead acid battery manufacturing area sources because no new sources are estimated during the next 3 years.

The proposed NESHAP for wood preserving area sources does not include testing, monitoring, or recordkeeping requirements because they are subject to management practices. The only new information collection requirements that would apply to these existing area sources would consist of initial notifications and records demonstrating compliance with the management practice requirements.

The annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 1,055 labor hours per year at a cost of $89,324 for approximately 400 existing wood preserving area sources. No capital/startup costs or operation and maintenance costs are associated with the proposed requirements. No costs or burden hours are estimated for new wood preserving area sources because no new sources are estimated during the next 3 years.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, disclose, or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR part 63 are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule would not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions.

For the purposes of assessing the impacts of the proposed area source NESHAP on small entities, small entity is defined as: (1) A small business that meets the Small Business Administration size standards for small businesses found at 13 CFR 121.201 (less than 1,000 employees for acrylic and modacrylic fiber production and chromium compounds manufacturing and less than 500 employees for carbon black production, flexible polyurethane foam production and fabrication, lead-acid battery manufacturing, and wood preserving); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of the proposed rules on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. There would not be adverse impacts on existing area sources in any of the seven source categories because the proposed rules do not create any new requirements or burdens for existing sources other than minimal notification requirements.

Although the proposed NESHAP contain emissions control requirements for new area sources in all seven source categories, we are not specifically aware of any new sources being constructed now or planned in the next 3 years, and consequently, we did not estimate any impacts for new sources.

We continue to be interested in the potential impacts of the proposed action on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures by State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that the proposed rules do not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. Thus, the proposed rules are not subject to the requirements of sections 202 and 205 of the UMRA. In addition, the proposed rules do not significantly or uniquely affect small governments. The proposed rules contain no requirements that apply to such governments, impose no obligations upon them, and would not result in expenditures by them of $100 million or more in any one year or any disproportionate impacts on them. Therefore, the proposed rules are not subject to section 203 of the UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999) requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' are defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

The proposed rules do not have federalism implications. They would not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The proposed rules impose requirements on owners and operators of specified area sources and not State and local governments. Thus, Executive Order 13132 does not apply to the proposed rules.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175 (65 FR 67249, November 6, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' The proposed rules do not have tribal implications, as specified in Executive Order 13175. They would not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. The proposed rules impose requirements on owners and operators of specified area sources and not tribal governments. Thus, Executive Order 13175 does not apply to the proposed rules.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045, ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, EPA must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. EPA interprets Executive Order 13045 as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. These proposed rules are not subject to the Executive Order 13045 because they are based solely on technology performance.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

The proposed rules are not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001) because they are not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, we have concluded that these proposed rules are not likely to have any adverse energy effects because energy requirements would remain at existing levels. No additional pollution controls or other equipment that would consume energy are required by the proposed rules.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement

Act (NTTAA) of 1995 (Pub. L. 104–113, Section 12(d), 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities, unless to do so would be inconsistent with applicable law or otherwise impractical. The VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency does not use available and applicable VCS.

The proposed rules involve technical standards. The EPA cites the following standards: EPA Methods 1, 1A, 2, 2A, 2C, 2D, 2F, 2G, 3, 3A, 3B, 4, 5, 5D, 9, or 22 in 40 CFR part 60, appendix A. The method ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference-see 40 CFR 63.14) is cited in this proposed rule for its manual method for measuring the oxygen, carbon dioxide, and carbon monoxide content of the exhaust gas. This part of ASME PTC 19.10–1981 is an acceptable alternative to EPA Method 3B. This ASTM method is a VCS.

Consistent with the NTTAA, EPA conducted searches to identify VCS in addition to these EPA methods. No applicable VCS were identified for EPA Methods 1A, 2A, 2D, 2F, 2G, 5D, 9, or 22. The search and review results are in the docket for these proposed rules.

The search for emissions measurement procedures identified 12 other VCS. The EPA determined that these 12 standards identified for measuring emissions of the HAP or surrogates subject to emissions standards in these proposed rules were impractical alternatives to EPA test methods. Therefore, EPA does not intend to adopt these standards for this purpose. The reasons for the determinations for the 12 methods discussed in a memorandum included in the docket for these proposed rules.

For the methods required or referenced by these proposed rules, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any required testing methods, performance specifications, or procedures under § 63.7(f) and § 63.8(f) of subpart A of the General Provisions.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that these proposed rules will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. These proposed rules establish national standards for each area source category.

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Incorporations by reference, Reporting and recordkeeping requirements.

Dated: March 22, 2007.

Stephen L. Johnson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is proposed to be amended as follows:

PART 63—[AMENDED]

1. The authority citation for part 63 continues to read as follows:

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

Subpart A—[Amended]

2. Section 63.14 is amended by revising paragraph (i)(1) to read as follows:

§ 63.14 Incorporations by reference.

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(i) * * *

(1) ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus],'' IBR approved for §§ 63.309(k)(1)(iii), 63.865(b), 63.3166(a)(3), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), 63.11410(j)(1)(iii), and Table 5 of subpart DDDDD of this part.

* * * * *

3. Part 63 is amended by adding subpart LLLLLL to read as follows:

Subpart LLLLLL—National Emission Standards for Hazardous Air Pollutants for Acrylic and Modacrylic Fibers Production Area Sources

Sec.

Applicability and Compliance Dates

63.11393 Am I subject to this subpart?
63.11394 What are my compliance dates?

Standards and Compliance Requirements

63.11395 What are the standards and compliance requirements for existing sources?
63.11396 What are the standards and compliance requirements for new sources?

Other Requirements and Information

63.11397 What General Provisions apply to this subpart?
63.11398 What definitions apply to this subpart?
63.11399 Who implements and enforces this subpart?
Table 1 to Subpart LLLLLL of Part 63—Applicability of General Provisions to Subpart LLLLLL

Applicability and Compliance Dates

§ 63.11393 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate an acrylic or modacrylic fiber production plant that is an area source of hazardous air pollutant (HAP) emissions.

(b) This subpart applies to each new or existing affected source. The affected source is each acrylic or modacrylic fiber plant.

(1) An affected source is existing if you commenced construction or reconstruction of the affected source before April 4, 2007.

(2) An affected source is new if you commenced construction or reconstruction of the affected source on or after April 4, 2007.

(c) This subpart does not apply to research and development facilities, as defined in section 112(c)(7) of the Clean Air Act (CAA).

(d) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 63.11394 What are my compliance dates?

(a) If you own or operate an existing affected source, you must achieve compliance with the applicable provisions in this subpart no later than 6 months after the date of publication of the final rule in the **Federal Register**.

(b) If you startup a new affected source on or before the date of publication of the final rule in the **Federal Register**, you must achieve compliance with the applicable provisions of this subpart not later than the date of publication of the final rule in the **Federal Register**.

(c) If you startup a new affected source after the date of publication of the final rule in the **Federal Register**, you must achieve compliance with the provisions in this subpart upon startup of your affected source.

Standards and Compliance Requirements

§ 63.11395 What are the standards and compliance requirements for existing sources?

(a) You must operate and maintain capture or enclosure systems that collect the gases and fumes containing AN released from polymerization process equipment and monomer recovery process equipment and convey the collected gas stream through a closed vent system to a control device.

(b) You must not discharge to the atmosphere through any combination of stacks or other vents captured gases containing AN in excess of the emissions limits in paragraphs (b)(1) and (2) of this paragraph.

(1) 0.2 pounds of AN per hour (lb/hr) from the control device for polymerization process equipment.

(2) 0.05 lb/hr of AN from the control device for monomer recovery process equipment.

(c) If you use a wet scrubber control device, you must comply with the control device parameter operating limits in paragraphs (c)(1) and (2) of this section.

(1) You must maintain the daily average water flow rate to a wet scrubber used to control polymerization process equipment at a minimum of 50 liters per minute (l/min). If the water flow to the wet scrubber ceases, the polymerization reactor(s) must be shut down.

(2) You must maintain the daily average water flow rate to a wet scrubber used to control monomer recovery process equipment at a minimum of 30 l/min.

(d) You must comply with the requirements of the New Source Performance Standard for Volatile Organic Liquids (40 CFR part 60, subpart Kb) for vessels that store acrylonitrile. The provisions in 40 CFR 60.114b do not apply to this subpart.

(e) You must operate continuous parameter monitoring systems (CPMS) to measure and record the water flow rate to a wet scrubber control device for the polymerization process equipment and the monomer recovery process equipment. The CPMS must record the water flow rate at least every 15 minutes and determine and record the daily average water flow rate.

(f) You must determine compliance with the daily average control device parameter operating limits for water flow rate in paragraph (c) of this section on a monthly basis and submit a summary report to EPA or the delegated authority on a quarterly basis. Should the daily average water flow rate to a wet scrubber control device for the polymerization process equipment fall below 50 l/min or the daily water flow rate to a wet scrubber control device for the monomer recovery process equipment fall below 30 l/min, you must notify EPA or the delegated authority in writing within 10 days of the identification of the exceedance.

(g) You must keep records of each monthly compliance determination for the water flow rate operating parameter limits in a permanent form suitable for inspection and retain the records for at least 2 years following the date of each compliance determination.

(h) You must conduct a performance test for each control device for polymerization process equipment and monomer recovery process equipment subject to an emissions limit in paragraph (b) of this section within 180 days of your compliance date and report the results in your notification of compliance status. You must conduct each test according to the requirements in 40 CFR 63.7 and § 63.1104 of subpart YY. You are not required to conduct a performance test if a prior performance test was conducted using the methods specified in § 63.1104 of subpart YY and either no process changes have been made since the test, or you can demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process changes.

(i) If you do not use a wet scrubber control device for the polymerization process equipment or the monomer recovery process equipment, you must submit a monitoring plan to EPA or the delegated authority for approval. Each plan must contain the information in paragraphs (i)(1) through (5) of this section.

(1) A description of the device;

(2) Test results collected in accordance with § 63.1104 of subpart YY verifying the performance of the device for reducing AN to the levels required by this subpart;

(3) Operation and maintenance plan for the control device (including a preventative maintenance schedule consistent with the manufacturer's instructions for routine and long-term maintenance) and continuous monitoring system.

(4) A list of operating parameters that will be monitored to maintain continuous compliance with the applicable emissions limits; and

(5) Operating parameter limits based on monitoring data collected during the performance test.

(j) If you do not operate a monomer recovery process that removes AN prior to spinning, you must comply with the requirements in paragraph (j)(1), (2), or (3) of this section for each fiber spinning line that uses a spin dope produced from either a suspension polymerization process or solution polymerization process.

(1) You must reduce the AN concentration of the spin dope to less than 100 parts per million by weight (ppmw); or

(2) You must design and operate a fiber spinning line enclosure according to the requirements in § 63.1103(b)(4) of subpart YY and reduce AN emissions by 85 weight-percent or more by venting emissions from the enclosure through a closed vent system to any combination of control devices meeting the requirements in § 63.982(a)(2) of subpart SS; or

(3) You must reduce AN emissions from the spinning line to less than or equal to 0.5 pounds of AN per ton (lb/ton) of acrylic and modacrylic fiber produced.

§ 63.11396 What are the standards and compliance requirements for new sources?

(a) You must comply with the requirements in paragraph (a)(1) or (2) of this section for each process vent where the AN concentration of the vent stream is equal to or greater than 50 parts per million by volume (ppmv) and the average flow rate is equal to or greater than 0.005 cubic meters per minute, as determined by the applicability and assessment procedures in § 63.1104 of subpart YY.

(1) You must reduce emissions of AN by 98 weight-percent or limit the concentration of AN in the emissions to no more than 20 ppmv, whichever is less stringent, by venting emissions through a closed vent system to any combination of control devices meeting

the requirements for process vents in § 63.982(a)(2) of subpart SS; or

(2) You must reduce emissions of AN by using a flare that meets the requirements of § 63.987 of subpart SS.

(b) You must comply with the requirements in paragraph (b)(1), (2), or (3) of this section for each fiber spinning line that uses a spin dope produced from either a suspension polymerization process or solution polymerization process.

(1) You must reduce the AN concentration of the spin dope to less than 100 parts per million by weight (ppmw); or

(2) You must design and operate a fiber spinning line enclosure according to the requirements in § 63.1103(b)(4) of subpart YY and reduce AN emissions by 85 weight-percent or more by venting emissions from the enclosure through a closed vent system to any combination of control devices meeting the requirements in § 63.982(a)(2) of subpart SS; or

(3) You must reduce AN emissions from the spinning line to less than or equal to 0.5 pounds of AN per ton (lb/ton) of acrylic and modacrylic fiber produced.

(c) You must comply with the requirements for storage vessels holding acrylonitrile as shown in Table 2 to § 63.1103(b)(3)(i) of subpart YY.

(d) You must comply with the requirements for equipment that contains or contacts 10 percent by weight or more of AN and operates 300 hours per year as shown in Table 2 to § 63.1103(b)(3)(i) of subpart YY.

(e) You must comply with the requirements for process wastewater and maintenance wastewater from an acrylic and modacrylic fiber production process as shown in Table 2 to § 63.1103(b)(3)(i) of subpart YY.

(f) You must comply with all testing, monitoring, recordkeeping, and reporting requirements in subpart SS (for process vents); subpart SS or WW (for AN tanks); subpart TT or UU (for equipment leaks); and subpart G (for process wastewater and maintenance wastewater). Only the provisions in §§ 63.132 through 63.148 and §§ 63.151 through 63.153 of subpart G apply to this subpart.

(g) If you use a control device other than a wet scrubber, flare, incinerator, boiler, process heater, absorber, condenser, or carbon adsorber, you must prepare and submit a monitoring plan to the Administrator for approval. Each plan must contain the information in paragraphs (g)(1) through (5) of this section.

(1) A description of the device;

(2) Test results collected in accordance with paragraph (f) of this section verifying the performance of the device for reducing AN to the levels required by this subpart;

(3) Operation and maintenance plan for the control device (including a preventative maintenance schedule consistent with the manufacturer's instructions for routine and long-term maintenance) and continuous monitoring system.

(4) A list of operating parameters that will be monitored to maintain continuous compliance with the applicable emissions limits; and

(5) Operating parameter limits based on monitoring data collected during the performance test.

Other Requirements and Information

§ 63.11397 What General Provisions apply to this subpart?

(a) You must meet the requirements of the General Provisions in 40 CFR part 63, subpart A, as shown in Table 1 to this subpart.

(b) If you own or operate an existing affected source, your notification of compliance status required by § 63.9(h) must include the following information:

(1) This certification of compliance, signed by a responsible official, for the standards in § 63.11395(a): ''This facility complies with the management practices required in § 63.11395(a) for operation of capture systems for polymerization process equipment and monomer recovery process equipment.''

(2) This certification of compliance, signed by a responsible official, for the emissions limits in § 63.11395(b): ''This facility complies with the emissions limits in § 63.11395(b) for control devices serving the polymerization process equipment and monomer recovery process equipment based on previous performance tests in accordance with § 63.11395(h).'' If you conduct a performance test to demonstrate compliance, you must include the results of the performance test.

(3) This certification of compliance, signed by a responsible official, for the standards for storage tanks in § 63.11396(d): ''This facility complies with the requirements of 40 CFR part 60, subpart Kb for each tank that stores acrylonitrile.''

(4) This certification of compliance, signed by a responsible official, for the requirement in Table 1 to subpart LLLLLL for preparation of a startup, shutdown, and malfunction plan: ''This facility has prepared a startup, shutdown, and malfunction plan in accordance with the requirements of 40 CFR 63.6(e)(3).''

(c) If you own or operate a new affected source, your notification of compliance status required by § 63.9(h) must include:

(1) The results of the initial performance test or compliance demonstration for each process vent (including closed vent system and control device, flare, or recovery device), fiber spinning line, AN storage tank, equipment, and wastewater stream subject to this subpart.

(2) This certification of compliance, signed by a responsible official, for the applicable emissions limit in § 63.11396(a) for process vents: ''This facility complies with the emissions limits in § 63.11396(a) for each process vent subject to control.''

(3) This certification of compliance, signed by a responsible official, for the applicable emissions limit in § 63.11396(b) for each fiber spinning line: ''This facility complies with the emissions limit and/or management practice requirements in § 63.11396(b)(1), (2), or (3) for each fiber spinning line.''

(4) This certification of compliance, signed by a responsible official, for the storage tank requirements in § 63.11396(c): ''This facility complies with the requirements for storage vessels holding acrylonitrile as shown in Table 2 to § 63.1103(b)(3)(i) of subpart YY.''

(5) This certification of compliance, signed by a responsible official, for the equipment leak requirements in § 63.11396(d): ''This facility complies with the requirements for all equipment that contains or contacts 10 percent by weight or more of AN and operates 300 hours per year or more as shown in Table 2 to § 63.1103(b)(3)(i) of subpart YY.''

(6) This certification of compliance, signed by a responsible official, for the process wastewater and maintenance wastewater requirements in § 63.11396(e): ''This facility complies with the requirements in Table 2 to § 63.1103(b)(3)(i) of subpart YY for each process wastewater stream and each maintenance wastewater stream.''

(d) If you own or operate a new affected source, you must report any deviation from the requirements of this subpart in the semiannual report required by 40 CFR 63.10(e)(3).

§ 63.11398 What definitions apply to this subpart?

Acrylic fiber means a manufactured synthetic fiber in which the fiber-forming substance is any long-chain synthetic polymer composed of at least 85 percent by weight of acrylonitrile units.

Acrylic and modacrylic fibers production means the production of either of the following synthetic fibers composed of acrylonitrile units: acrylic fiber or modacrylic fiber.

Acrylonitrile solution polymerization means a process where acrylonitrile and comonomers are dissolved in a solvent to form a polymer solution (typically polyacrylonitrile). The polyacrylonitrile is soluble in the solvent. In contrast to suspension polymerization, the resulting reactor polymer solution (spin dope) is filtered and pumped directly to the fiber spinning process.

Acrylonitrile suspension polymerization means a polymerization process where small drops of acrylonitrile and comonomers are suspended in water in the presence of a catalyst where they polymerize under agitation. Solid beads of polymer are formed in this suspension reaction which are subsequently filtered, washed, refiltered, and dried. The beads must be subsequently redissolved in a solvent to create a spin dope prior to introduction to the fiber spinning process.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emissions limitation or management practice;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emissions limitation or management practice in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Equipment means each of the following that is subject to this subpart: Pump, compressor, agitator, pressure relief device, sampling collection system, open-ended valve or line, valve connector, instrumentation system in organic HAP service which contains or contacts greater than 10 percent by weight of acrylonitrile and operates more than 300 hours per year.

Fiber spinning line means the group of equipment and process vents associated with acrylic or modacrylic fiber spinning operations. The fiber spinning line includes (as applicable to the type of spinning process used) the blending and dissolving tanks, spinning solution filters, wet spinning units, spin bath tanks, and the equipment used downstream of the spin bath to wash, dry, or draw the spun fiber.

Maintenance wastewater means wastewater generated by the draining of process fluid from components in the process unit, whose primary product is a product produced by a source category subject to this subpart, into an individual drain system prior to or during maintenance activities. Maintenance wastewater can be generated during planned and unplanned shutdowns and during periods not associated with a shutdown. Examples of activities that can generate maintenance wastewaters include descaling of heat exchanger tubing bundles, cleaning of distillation column traps, draining of low legs and high point bleeds, draining of pumps into an individual drain system, and draining of portions of the process unit, whose primary product is a product produced by a source category subject to this subpart, for repair.

Modacrylic fiber means a manufactured synthetic fiber in which the fiber-forming substance is any long-chain synthetic polymer composed of at least 35 percent by weight of acrylonitrile units but less than 85 percent by weight of acrylonitrile units.

Monomer recovery process equipment means the collection of process units and associated process equipment used to reclaim the monomer for subsequent reuse, including but not limited to polymer holding tanks, polymer buffer tanks, monomer vacuum pump flush drum, and drum filter vacuum pump flush drum.

Polymerization process equipment means the collection of process units and associated process equipment used in the acrylonitrile polymerization process prior to the fiber spinning line, including but not limited to acrylonitrile storage tanks, recovered monomer tanks, monomer measuring tanks, monomer preparation tanks, monomer feed tanks, slurry receiver tanks, polymerization reactors, and drum filters.

Process vent means the point of discharge to the atmosphere (or point of entry into a control device, if any) of a gas stream from the acrylic and modacrylic fibers production process.

Process wastewater means wastewater, which during manufacturing or processing, comes into direct contact with or results from the production of use of any raw material, intermediate product, finished product, by-product, or waste product.

Responsible official means responsible official as defined at 40 CFR 70.2.

Spin dope means the liquid mixture of polymer and solvent that is fed to the spinneret to form the acrylic and modacrylic fibers.

Wastewater means process wastewater that:

(1) Contains either an annual concentration of organic hazardous air pollutants listed in Table 9 to subpart G of at least 5 parts per million by weight at the point of determination and has an annual average flow rate of 0.02 liter per minute, or contains an annual average concentration of organic hazardous air pollutants listed in Table 9 to subpart G of at least 10,000 parts per million by weight at the point of determination at any flow rate; and

(2) Is discarded from a polymerization production process, monomer recovery process, or other production operation.

§ 63.11399 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as a State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency pursuant to 40 CFR subpart E, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency within your State.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the approval authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(1) Approval of an alternative non-opacity emissions standard under § 63.6(g).

(2) Approval of a major change to a test method under § 63.7(e)(2)(ii) and (f). A ''major change to test method'' is defined in § 63.90.

(3) Approval of a major change to monitoring under § 63.8(f). A ''major change to monitoring'' is defined in § 63.90.

(4) Approval of a major change to recordkeeping/reporting under § 63.10(f). A ''major change to recordkeeping/reporting'' is defined in § 63.90.

As required in § 63.11397(a), you must comply with the requirements of the NESHAP General Provisions (40 CFR part 63, subpart A) as shown in the following table.

TABLE 1 TO SUBPART LLLLLL OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART LLLLLL

Citation	Subject	Applies to subpart LLLLLL?	Explanation
63.1(a)(1), (a)(2), (a)(3), (a)(4), (a)(6), (a)(10)–(a)(12) (b)(1), (b)(3), (c)(1), (c)(2), (c)(5), (e).	Applicability	Yes.	
63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3), (c)(4), (d).	Reserved	No.	
63.2	Definitions	Yes.	
63.3	Units and Abbreviations	Yes.	
63.4	Prohibited Activities and Circumvention.	Yes.	
63.5	Preconstruction Review and Notification Requirements.	No.	
63.6(a), (b)(1)–(b)(5), (b)(7), (c)(1), (c)(2), (c)(5), (e)(1), (e)(3)(i), (e)(3)(iii)–(e)(3)(ix), (f) (g), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes	Subpart LLLLLL requires new and existing sources to comply with requirements for startups, shutdowns, and malfunctions in § 63.6(e)(3).
63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv).	Reserved	No.	
63.6(h)(1)–(h)(4), (h)(5)(i)–(h)(5)(iii), (h)(6)–(h)(9).		No	Subpart LLLLLL does not include opacity or visible emissions standards or require a continuous opacity monitoring system.
63.7(a), (e), (f), (g), (h)	Performance Testing Requirements.	Yes/No	Subpart LLLLLL requires performance tests for new and existing sources; a test for an existing source is not required if a prior test meets the conditions in § 63.11395(h).
63.7(b), (c)		Yes/No	Requirements for notification of performance test and for quality assurance program apply to new sources but not existing sources.
63.8(a)(1), (a)(2), (b), (c)(1)–(c)(3), (f)(1)–(5).	Monitoring Requirements	Yes.	
63.8(a)(3)	Reserved	No.	
63.8(a)(4)		Yes	Requirements apply to new sources if flares are the selected control option.
63.8(c)(4)–(c)(8), (d), (e), (f)(6), (g).		Yes	Requirements apply to new sources but not to existing sources.
63.9(a), (b)(1), (b)(5), (c), (d), (i), (j).	Notification Requirements	Yes.	
63.9(e)		Yes/No	Notification of performance test is required for new area sources.
63.9(b)(2)		Yes	Initial notification of applicability is required for new and existing area sources.
63.9(b)(3), (h)(4)	Reserved	No.	
63.9(b)(4), (h)(5)		No.	
63.9(f), (g)		No	Subpart LLLLLL does not require a continuous opacity monitoring system or continuous emissions monitoring system.
63.9(h)(1)–(h)(3), (h)(6)		Yes	Notification of compliance status is required for new and existing area sources.
63.10(a)	Recordkeeping Requirements.	Yes.	
(b)(1)		Yes/No	Record retention requirement applies to new area sources but not existing area sources. Subpart LLLLLL establishes 2-year retention period for existing area sources.
63.10(b)(2)		Yes	Recordkeeping requirements for startups, shutdowns, and malfunctions apply to new and existing area sources.
63.10(b)(3)		Yes	Recordkeeping requirements for applicability determinations apply to new area sources.
63.10(c)(1), (c)(5)–(c)(14)		Yes/No	Recordkeeping requirements for continuous parameter monitoring systems apply to new sources but not existing sources.
63.10(c)(2)–(c)(4), (c)(9)	Reserved	No.	
63.10(d)(1), (d)(4), (e)(1), (e)(2), (f).	Reporting Requirements	Yes.	
63.10(d)(2)		Yes	Report of performance test results applies to each area source required to conduct a performance test.
63.10(d)(3)		No	Subpart LLLLLL does not include opacity or visible emissions limits.

TABLE 1 TO SUBPART LLLLLL OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART LLLLLL—Continued

Citation	Subject	Applies to subpart LLLLLL?	Explanation
63.10(d)(5)		Yes	Requirements for startup, shutdown, and malfunction reports apply to new and existing area sources.
(e)(1)–(e)(2), (e)(4)		No	Subpart LLLLLL does not require a continuous emissions monitoring system or continuous opacity monitoring system.
63.10(e)(3)		Yes/No	Semiannual reporting requirements for excess emissions and parameter monitoring exceedances apply to new area sources but not existing area sources.
63.11	Control Device Requirements.	Yes	Requirements apply to new sources if flares are the selected control option.
63.12	State Authorities and Delegations.	Yes.	
63.13	Addresses	Yes.	
63.14	Incorporations by Reference	Yes.	
63.15	Availability of Information and Confidentiality.	Yes.	
63.16	Performance Track Provisions.	Yes.	

4. Part 63 is amended by adding subpart MMMMMM to read as follows:

Subpart MMMMMM—National Emission Standards for Hazardous Air Pollutants for Carbon Black Production Area Sources

Sec.

Applicability and Compliance Dates

63.11400 Am I subject to this subpart?
63.11401 What are my compliance dates?

Standards and Compliance Requirements

63.11402 What are the standards and compliance requirements for new and existing sources?
63.11403 [Reserved]

Other Requirements and Information

63.11404 What General Provisions apply to this subpart?
63.11405 What definitions apply to this subpart?
63.11406 Who implements and enforces this subpart?

Applicability and Compliance Dates

§ 63.11400 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate a carbon black production facility that is an area source of hazardous air pollutant (HAP) emissions.

(b) This subpart applies to each new or existing affected source. The affected source is each carbon black production process unit. The affected source includes all waste management units, maintenance wastewater, and equipment components that contain or contact HAP that are associated with the carbon black production unit.

(1) An affected source is an existing source if you commenced construction or reconstruction of the affected source before April 4, 2007.

(2) An affected source is new if you commenced construction or reconstruction of the affected source on or after April 4, 2007.

(c) This subpart does not apply to research and development facilities, as defined in section 112(c)(7) of the Clean Air Act (CAA).

(d) If you own or operate an area source subject to this subpart, you must obtain a permit under 40 CFR part 70 or 40 CFR part 71.

§ 63.11401 What are my compliance dates?

(a) If you own or operate an existing affected source, you must achieve compliance with the applicable provisions of this subpart by the date of publication of the final rule in the **Federal Register**.

(b) If you startup a new affected source on or before the date of publication of the final rule in the **Federal Register**, you must achieve compliance with the applicable provisions of this subpart not later than the date of publication of the final rule in the **Federal Register**.

(c) If you startup a new affected source after the date of publication of the final rule in the **Federal Register**, you must achieve compliance with the applicable provisions of this subpart upon startup of your affected source.

Standards and Compliance Requirements

§ 63.11402 What are the standards and compliance requirements for new and existing sources?

You must meet all the requirements in § 63.1103(f) of subpart YY.

§ 63.11403 [Reserved]

Other Requirements and Information

§ 63.11404 What General Provisions apply to this subpart?

The provisions in 40 CFR part 63, subpart A, applicable to this subpart are §§ 63.1 through 63.5 and §§ 63.11 through 63.16.

§ 63.11405 What definitions apply to this subpart?

The terms used in this subpart are defined in §§ 63.1101 and 63.1103(f)(2).

§ 63.11406 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as a State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency pursuant to 40 CFR subpart E, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency within your State.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the approval authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(1) Approval of an alternative non-opacity emissions standard under § 63.992(b)(1).

(2) Approval of a major change to test methods under § 63.7(e)(2)(ii) and (f). A ''major change to test method'' is defined in § 63.90.

(3) Approval of a major change to monitoring under § 63.8(f). A ''major change to monitoring'' is defined in § 63.90.

(4) Approval of a major change to recordkeeping/reporting under § 63.10(f). A ''major change to recordkeeping/reporting'' is defined in § 63.90.

5. Part 63 is amended by adding subpart NNNNNN to read as follows:

Subpart NNNNNN—National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources: Chromium Compounds

Sec.

Applicability and Compliance Dates

63.11407 Am I subject to this subpart?
63.11408 What are my compliance dates?

Standards and Compliance Requirements

63.11409 What are the standards?
63.11410 What are the compliance requirements?

Other Requirements and Information

63.11411 What General Provisions apply to this subpart?
63.11412 What definitions apply to this subpart?
63.11413 Who implements and enforces this subpart?
Table 1 to Subpart NNNNNN of Part 63—HAP Emissions Units
Table 2 to Subpart NNNNNN of Part 63—Applicability of General Provisions to Subpart NNNNNN

Applicability and Compliance Dates

§ 63.11407 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate a chromium compounds manufacturing facility that is an area source of hazardous air pollutant (HAP) emissions.

(b) This subpart applies to each new or existing affected source. The affected source is each chromium compounds manufacturing facility.

(1) An affected source is existing if you commenced construction or reconstruction of the affected source before April 4, 2007.

(2) An affected source is new if you commence construction or reconstruction of the affected source on or after April 4, 2007.

(c) This subpart does not apply to research and development facilities, as defined in section 112(c)(7) of the CAA.

(d) If you own or operate an area source subject to this subpart, you must obtain a permit under 40 CFR part 70 or 40 CFR part 71.

§ 63.11408 What are my compliance dates?

(a) If you own or operate an existing affected source, you must achieve compliance with the applicable provisions in this subpart not later than 6 months after the date of publication of the final rule in the **Federal Register**.

(b) If you startup a new affected source on or before the date of publication of the final rule in the **Federal Register**, you must achieve compliance with the applicable provisions of this subpart not later than the date of publication of the final rule in the **Federal Register**.

(c) If you startup a new affected source after the date of publication of the final rule in the **Federal Register**, you must achieve compliance with the applicable provisions of this subpart upon startup of your affected source.

Standards and Compliance Requirements

§ 63.11409 What are the standards?

(a) You must operate a capture system that collects the gases and fumes released during the operation of each emissions unit listed in Table 1 of this subpart and conveys the collected gas stream to a particulate matter (PM) control device.

(b) You must not discharge to the atmosphere through any combination of stacks or other vents process gases from an emissions unit listed in Table 1 of this subpart that contain PM in excess of the allowable process rate determined according to Equation 1 of this section (for an emissions unit with a process rate of less than 30 tons per hour) or Equation 2 of this section (for an emissions unit with a process rate of 30 tons per hour or greater). If more than one process vents to a common stack, the applicable emissions limit for the stack is the sum of allowable emissions calculated for each process using Equation 1 or 2 of this section, as applicable.

$$E = 4.1 \times P^{0.67} \qquad (Eq. 1)$$

Where:

E = Emissions limit in pounds per hour (lb/hr); and

P = Process rate of emissions unit in tons per hour (ton/hr).

$$E = 55 \times P^{0.11} - 40 \qquad (Eq. 2)$$

§ 63.11410 What are the compliance requirements?

(a) *Existing sources.* If you own or operate an existing area source, you must comply with the requirements in paragraphs (b) through (e) of this section.

(b) *Initial control device inspection.* You must conduct an initial inspection of each PM control device according to the requirements in paragraphs (b)(1) through (4) of this section. You must conduct each inspection no later than 60 days after your applicable compliance date.

(1) For each baghouse, you must visually inspect the system ductwork and baghouse unit for leaks. You must also inspect the inside of each baghouse for structural integrity and fabric filter condition. You must record the results of the inspection and any maintenance action in the logbook required in paragraph (d) of this section.

(2) For each dry electrostatic precipitator, you must verify the proper functioning of the electronic controls for corona power and rapper operation, that the corona wires are energized, and that adequate air pressure is present on the rapper manifold. You must also visually inspect the system ductwork and electrostatic precipitator housing unit and hopper for leaks and inspect the interior of the electrostatic precipitator to determine the condition and integrity of corona wires, collection plates, hopper, and air diffuser plates.

(3) For each wet electrostatic precipitator, you must verify the proper functioning of the electronic controls for corona power, that the corona wires are energized, and that water flow is present. You must also visually inspect the system ductwork and electrostatic precipitator housing unit and hopper for leaks and inspect the interior of the electrostatic precipitator to determine the condition and integrity of corona wires, collection plates, plate wash spray heads, hopper, and air diffuser plates.

(4) For each wet scrubber, you must verify the presence of water flow to the scrubber. You must also visually inspect the system ductwork and scrubber unit for leaks and inspect the interior of the scrubber for structural integrity and the condition of the demister and spray nozzle.

(c) *Periodic inspections/maintenance.* Following the initial inspections, you must perform periodic inspections and maintenance of each PM control device according to the requirements in paragraphs (c)(1) through (4) of this section.

(1) You must inspect and maintain each baghouse according to the requirements in paragraphs (c)(1)(i) and (ii) of this section.

(i) You must conduct monthly visual inspections of the system ductwork for leaks.

(ii) You must conduct annual inspections of the interior of the baghouse for structural integrity and to determine the condition of the fabric filter.

(2) You must inspect and maintain each dry electrostatic precipitator according to the requirements in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must conduct a daily inspection to verify the proper functioning of the electronic controls for corona power and rapper operation, that the corona wires are energized, and that adequate air pressure is present on the rapper manifold.

(ii) You must conduct monthly visual inspections of the system ductwork, housing unit, and hopper for leaks.

(iii) You must conduct biennial inspections of the interior of the electrostatic precipitator to determine the condition and integrity of corona wires, collection plates, plate rappers, hopper, and air diffuser plates.

(3) You must inspect and maintain each wet electrostatic precipitator according to the requirements in paragraphs (c)(3)(i) through (iii) of this section.

(i) You must conduct a daily inspection to verify the proper functioning of the electronic controls for corona power, that the corona wires are energized, and that water flow is present.

(ii) You must conduct monthly visual inspections of the system ductwork, electrostatic precipitator housing unit, and hopper for leaks.

(iii) You must conduct biennial inspections of the interior of the electrostatic precipitator to determine the condition and integrity of corona wires, collection plates, plate rappers, hopper, and air diffuser plates.

(4) You must inspect and maintain each wet scrubber according to the requirements in paragraphs (c)(4)(i) through (iii) of this section.

(i) You must conduct a daily inspection to verify the presence of water flow to the scrubber.

(ii) You must conduct monthly visual inspections of the system ductwork and scrubber unit for leaks.

(iii) You must conduct annual inspections of the interior of the scrubber to determine the structural integrity and condition of the demister and spray nozzle.

(d) *Recordkeeping requirements.* You must record the results of each inspection and maintenance action in a logbook (written or electronic format). You must keep the logbook onsite and make the logbook available to the permitting authority upon request. You must keep records of the information specified in paragraphs (d)(1) through (4) of this section for 5 years following the date of each recorded action.

(1) The date and time of each recorded action for a fabric filter, the results of each inspection, and the results of any maintenance performed on the bag filters.

(2) The date and time of each recorded action for a wet or dry electrostatic precipitator (including ductwork), the results of each inspection, and the results of any maintenance performed on the electrostatic precipitator.

(3) The date and time of each recorded action for a wet scrubber (including ductwork), the results of each inspection, and the results of any maintenance performed on the wet scrubber.

(4) Records of all required monitoring data and supporting information including all calibration and maintenance records, original strip-chart recordings for continuous monitoring information, and copies of all reports required by this subpart. You must maintain records of required monitoring data in a form suitable and readily available for expeditious review. All records must be kept onsite and made available to EPA or the delegated authority for inspection upon request. You must maintain records of all required monitoring data and supporting information for at least 5 years from the date of the monitoring sample, measurement, report, or application.

(e) *Reports.* (1) You must report each deviation (an action or condition not in accordance with the requirements of this subpart, including upset conditions but excluding excess emissions) to the permitting agency on the next business day after becoming aware of the deviation. You must submit a written report within 2 business days which identifies the probable cause of the deviation and any corrective actions or preventative actions taken. All reports of deviations must be certified by a responsible official.

(2) You must submit semiannual reports of monitoring and recordkeeping activities to your permitting authority.

(3) You must submit the results of any maintenance performed on each PM control device within 30 days of a written request by the permitting authority.

(f) *New sources.* If you own or operate a new affected source, you must comply with the requirements in paragraphs (g) and (h) of this section.

(g) *Bag leak detection systems.* You must install, operate, and maintain a bag leak detection system on all baghouses used to comply with the PM emissions limit in § 63.11409 according to paragraph (g)(1) of this section; prepare and operate by a site-specific monitoring plan according to paragraph (g)(2) of this section; take corrective action according to paragraph (g)(3) of this section; and record information according to paragraph (g)(4) of this section.

(1) Each bag leak detection system must meet the specifications and requirements in paragraphs (g)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 0.00044 grains per actual cubic foot or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (g)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, you must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, you shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (g)(1)(vi) of this section.

(vi) Once per quarter, you may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (g)(2) of this section.

(vii) You must install the bag leak detection sensor downstream of the baghouse and upstream of any wet scrubber.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) You must develop and submit to the Administrator or delegated authority for approval a site-specific monitoring plan for each bag leak detection system. You must operate and maintain the bag leak detection system according to the

site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (g)(2)(i) through (vi) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored; and

(vi) Corrective action procedures as specified in paragraph (g)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

(3) For each bag leak detection system, you must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (g)(2)(vi) of this section, you must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

(i) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective baghouse compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the particulate emissions.

(4) You must maintain records of the information specified in paragraphs (g)(4)(i) through (iii) of this section for each bag leak detection system.

(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the alarm was alleviated within 3 hours of the alarm.

(h) *Other control devices.* If you use a control device other than a baghouse, you must prepare and submit a monitoring plan to EPA or the delegated authority for approval. Each plan must contain the information in paragraphs (h)(1) through (5) of this section.

(1) A description of the device;

(2) Test results collected in accordance with paragraph (i) of this section verifying the performance of the device for reducing PM to the levels required by this subpart;

(3) Operation and maintenance plan for the control device (including a preventative maintenance schedule consistent with the manufacturer's instructions for routine and long-term maintenance) and continuous monitoring system.

(4) A list of operating parameters that will be monitored to maintain continuous compliance with the applicable emissions limits; and

(5) Operating parameter limits based on monitoring data collected during the performance test.

(i) *Performance tests.* If you own or operate a new affected source, you must conduct a performance test for each emissions unit subject to an emissions limit in § 63.11409(b) within 180 days of your compliance date and report the results in your notification of compliance status. If you own or operate an existing affected source, you are not required to conduct a performance test if a prior performance test was conducted within the past five years of the effective date using the same methods specified in paragraph (j) of this section and either no process changes have been made since the test, or if you can demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process changes.

(j) *Test methods.* You must conduct each performance test according to the requirements in § 63.7 and paragraphs (j)(1) through (3) of this section.

(1) Determine the concentration of PM according to the following test methods in appendix A to part 60 of this chapter:

(i) Method 1 or 1A to select sampling port locations and the number of traverse points in each stack or duct. Sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere.

(ii) Method 2, 2A, 2C, 2D, 2F, or 2G to determine the volumetric flow rate of the stack gas.

(iii) Method 3, 3A, or 3B to determine the dry molecular weight of the stack gas. You may use ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses (incorporated by reference—see § 63.14) as an alternative to EPA Method 3B.

(iv) Method 4 to determine the moisture content of the stack gas.

(v) Method 5 or 5D to determine the concentration of particulate matter (front half filterable catch only). Three valid test runs are needed to comprise a performance test.

(2) During the test, you must operate each emissions unit within 10 percent of the normal process rate specified in your notification of compliance status. You must monitor and record the process rate during the test.

(3) Compute the mass emissions (E) in pounds per hour (lb/hr) for each test run using Equation 1 of this section and the process rate measured during the test. The PM emissions in lb/hr must be less than the allowable PM emissions rate for the emissions unit.

$$E = \frac{C \times Q}{K} \qquad (Eq. 3)$$

Where:

E = Mass emissions of PM, pounds per hour (lb/hr);

C = Concentration of PM, grains per dry standard cubic foot (gr/dscf);

Q = Volumetric flow rate of stack gas, dry standard cubic foot per hour (dscf/hr); and

K = Conversion factor, 7,000 grains per pound (gr/lb).

(k) *Startups, shutdown, and malfunctions.* The requirements in paragraphs (k)(1) and (2) of this section apply to the owner or operator of a new or existing affected source.

(1) Except as provided in paragraph (k)(2) of this section, you must report emissions in excess of a PM emissions limit established by this subpart lasting for more than 4 hours that result from a malfunction, a breakdown of process or control equipment, or any other abnormal condition by 9 a.m. of the next business day of becoming aware of the occurrence. You must provide the name and location of the facility, the nature

and cause of the malfunction or breakdown, the time when the malfunction or breakdown is first observed, the expected duration, and the estimated rate of emissions. You must also notify EPA or the delegated authority immediately when corrected measures have been accomplished and, if requested, submit a written report within 15 days after the request.

(2) As an alternative to the requirements in paragraph (k)(1) of this section, you must comply with the startup, shutdown, and malfunction requirements in 40 CFR 63.6(e)(3).

Other Requirements and Information

§ 63.11411 What General Provisions apply to this subpart?

(a) You must comply with the requirements of the General Provisions in 40 CFR part 63, subpart A as specified in Table 2 to this subpart.

(b) Your notification of compliance status required by § 63.9(h) must include the following information for a new or existing affected source:

(1) This certification of compliance, signed by a responsible official, for the standards in § 63.11409(a): ''This facility complies with the management practice requirements in § 63.11409(a) for installation and operation of capture systems for each emissions unit subject to an emissions limit in § 63.11409(b).''

(2) This certification of compliance by the owner or operator of an existing source (if applicable), signed by a responsible official, for the emissions limits in § 63.11409(b): ''This facility complies with the emissions limits in § 63.11409(b) based on a previous performance test in accordance with § 63.11410(i).''

(3) The process rate for each emissions point subject to an emissions limit in § 63.11409(b) that represents normal and representative production operations.

(4) The procedures used to measure and record the process rate for each emissions unit point to an emissions limit in § 63.11409(b).

(5) This certification of compliance by the owner or operator of an existing affected source, signed by a responsible official, for the control device inspection and maintenance requirements in § 63.11410(b) through (d): ''This facility has conducted an initial inspection of each control device according to the requirements in § 63.11410(b), will conduct periodic inspections and maintenance of control devices in accordance with § 63.11410(c), and will maintain records of each inspection and maintenance action in the logbook required by § 63.11410(d).''

(6) This certification of compliance by the owner or operator of a new affected source, signed by a responsible official, for the bag leak detection system monitoring plan requirement in § 63.11410(g)(2): ''This facility has an approved bag leak detection system monitoring plan in accordance with § 63.11410(g)(2).''

(7) Performance test results for each emissions unit at a new affected source (or each emissions point at an existing affected source if a test is required) in accordance with § 63.11410(j). The performance test results for a new affected source must identify the daily average parameter operating limit for each PM control device.

(8) If applicable, this certification of compliance by the owner or operator of a new or existing source, signed by a responsible official, for the requirement in paragraph (k)(2) of this section to comply with the startup, shutdown, and malfunction provisions in 40 CFR 63.6(e)(3): ''This facility has prepared a startup, shutdown, and malfunction plan in accordance with 40 CFR 63.6(e)(3)''.

§ 63.11412 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in 40 CFR 63.2, and in this section as follows:

Bag leak detection system means a system that is capable of continuously monitoring relative particulate matter (dust loadings) in the exhaust of a baghouse to detect bag leaks and other upset conditions. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, light scattering, light transmittance, or other effect to continuously monitor relative particulate matter loadings.

Chromic acid means chromium trioxide (CrO_3). It is produced by the electrolytic reaction or acidification of sodium dichromate.

Chromium compounds manufacturing means any process that uses chromite ore as the basic feedstock to manufacture chromium compounds, primarily sodium dichromate, chromic acid, and chromic oxide.

Chromite ore means an oxide of chromium and iron ($FeCr_2O_4$) that is the primary feedstock for chromium compounds manufacturing.

Chromic oxide means Cr_2O_3. In the production of chromic oxide, ammonium sulfate and sodium dichromate that have been concentrated by evaporation are mixed and fed to a rotary roasting kiln to produce chromic oxide, sodium sulfate and nitrogen gas.

Roasting means a heating (oxidizing) process where ground chromite ore is mixed with alkaline material (such as soda ash, sodium bicarbonate, and sodium hydroxide) and fed to a rotary kiln where it is heated to about 2,000 °F, converting the majority of the chromium in the ore from trivalent to hexavalent chromium.

Sodium chromate means Na_2CrO_4. It is produced by roasting chromite ore in a rotary kiln.

Sodium dichromate means sodium bichromate or sodium bichromate dihydrate and is known technically as sodium dichromate dihydrate ($Na_2Cr_2O_7.2H_2O$). It is produced by the electrolytic reaction or acidification of sodium chromate.

§ 63.11413 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. EPA, or a delegated authority such as a State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency pursuant to 40 CFR subpart E, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(1) Approval of an alternative non-opacity emissions standard under § 63.6(g).

(2) Approval of a major change to test methods under § 63.7(e)(2)(ii) and (f). A ''major change to test method'' is defined in § 63.90.

(3) Approval of a major change to monitoring under § 63.8(f). A ''major change to monitoring'' is defined in § 63.90.

(4) Approval of a major change to recordkeeping/reporting under § 63.10(f). A ''major change to recordkeeping/reporting'' is defined in § 63.90.

As required in § 63.11409, you must install and operate capture systems and comply with the applicable emissions limit for each emissions point shown in the following table.

TABLE 1 TO SUBPART NNNNNN OF PART 63.—HAP EMISSIONS UNITS

Process	Emissions points
1. Sodium chromate production	a. Ball mill used to grind chromite ore. b. Dryer used to dry chromite ore. c. Rotary kiln used to roast chromite ore to produce sodium chromate. d. Secondary rotary kiln used to recycle and refine residues containing chromium compounds. e. Filter for sodium chromate slurry. f. Quench tanks.
2. Sodium dichromate production ...	a. Stack on the electrolytic cell system used to produce sodium dichromate. b. Sodium dichromate crystallization unit. c. Sodium dichromate evaporation unit. d. Sodium dichromate drying unit.
3. Chromic acid production	a. Electrolytic cell system used to produce chromic acid. b. Reactor used to produce chromic acid. c. Chromic acid crystallization unit. d. Chromic acid dryer.
4. Chromic oxide production	a. Primary rotary roasting kiln used to produce chromic oxide. b. Chromic oxide filter. c. Chromic oxide dryer. d. Chromic oxide grinding unit. e. Chromic oxide storage vessel. f. Secondary rotary roasting kiln. g. Quench tanks.
5. Chromium hydrate production	a. Furnace used to produce chromium hydrate. b. Chromium hydrate grinding unit.

As required in § 63.11411(a), you must comply with the requirements of the General Provisions (40 CFR part 63, subpart A) as shown in the following table.

TABLE 2 TO SUBPART NNNNNN OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART NNNNNN

Citation	Subject	Applies to subpart NNNNNN?	Explanation
63.1(a)(1), (a)(2), (a)(3), (a)(4), (a)(6), (a)(10)-(a)(12), (b)(1), (b)(3), (c)(1), (c)(2), (c)(5), (e).	Applicability	Yes.	
63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3), (c)(4), (d).	Reserved	No.	
63.2	Definitions	Yes.	
63.3	Units and Abbreviations	Yes.	
63.4	Prohibited Activities and Circumvention.	Yes.	
63.5	Preconstruction Review and Notification Requirements.	No.	
63.6(a), (b)(1)–(b)(5), (b)(7), (c)(1), (c)(2), (c)(5), (e)(1), (e)(3)(i), (e)(3)(iii)–(e)(3)(ix), (f), (g), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes	The startup, shutdown, and malfunction requirements in § 63.6(e)(3) apply at new and existing area sources that choose to comply with § 63.11410(k)(2) instead of the requirements in § 63.11410(k)(1).
63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv).	Reserved	No.	
63.6(h)(1)–(h)(4), (h)(5)(i)–(h)(5)(iii), (h)(6)–(h)(9).	No	Subpart NNNNNN does not include opacity or visible emissions standards or require a continuous opacity monitoring system.	
63.7(a), (e), (f), (g), (h)	Performance Testing Requirements.	Yes	Subpart NNNNNN requires a performance test for a new source; a test for an existing source is not required under the conditions specified in § 63.11410(i).
63.7(b), (c)		Yes/No	Requirements for notification of performance test and for quality assurance program apply to new area sources but not existing area sources.
63.8(a)(1), (a)(2), (b), (c)(1)–(c)(3), (f)(1)–(5).	Monitoring Requirements	Yes.	
63.8(a)(3)	Reserved	No.	
63.8(a)(4)		No	Subpart NNNNNN does not require flares.

TABLE 2 TO SUBPART NNNNNN OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART NNNNNN—Continued

Citation	Subject	Applies to subpart NNNNNN?	Explanation
63.8(c)(4)–(c)(8), (d), (e), (f)(6), (g).		No	Subpart NNNNNN establishes requirements for continuous parameter monitoring systems.
63.9(a), (b)(1), (b)(5), (c), (d), (i), (j).	Notification Requirements	Yes.	
63.9(e)		Yes/No	Notification of performance test is required only for new area sources.
63.9(b)(2)		Yes.	
63.9(b)(3), (h)(4)	Reserved	No.	
63.9(b)(4), (h)(5)		No.	
63.9(f), (g)		No	Subpart NNNNNN does not include opacity or visible emissions standards or require a continuous opacity monitoring system or continuous emissions monitoring system.
63.9(h)(1)–(h)(3), (h)(6)		Yes.	
63.10(a), (b)(1), (b)(2)(xii), (b)(2)(xiv), (b)(3).	Recordkeeping Requirements.	Yes.	
63.10(b)(2)(i)–(b)(2)(v)		Yes	Recordkeeping requirements for startups, shutdowns, and malfunctions apply to new and existing area sources that choose to comply with § 63.11410(k)(2).
63.10(b)(2)(vi)–(b)(2)(ix), (c)(1), (c)(5)–(c)(14).		Yes/No	Requirements apply to continuous parameter monitoring systems at new area sources but not existing area sources.
63.10(b)(2)(vii)(A)–(B), (b)(2)(x), (b)(2)(xiii).		No.	
63.10(c)(2)–(c)(4), (c)(9)	Reserved	No.	
63.10(d)(1), (d)(4), (e)(1), (e)(2), (f).	Reporting Requirements	Yes.	
63.10(d)(2)		Yes	Report of performance test results applies to new area sources; requirement applies to existing area sources if the permitting authority requests a performance test.
63.10(d)(3)		No	Subpart NNNNNN does not include opacity or visible emissions limits.
63.10(d)(5)		Yes	Requirements for startup, shutdown, and malfunction reports apply to new and existing area sources that choose to comply with § 63.11410(k)(2).
63.10(e)(1)–(e)(2), (e)(4)		No	Subpart NNNNNN does not require a continuous emissions monitoring system or continuous opacity monitoring system.
63.10(e)(3)		Yes/No	Semiannual reporting requirements apply to new area sources but not existing area sources.
63.11	Control Device Requirements.	No	Subpart NNNNNN does not require flares.
63.12	State Authorities and Delegations.	Yes.	
63.13	Addresses	Yes.	
63.14	Incorporations by Reference.	Yes.	
63.15	Availability of Information and Confidentiality.	Yes.	
63.16	Performance Track Provisions.	Yes.	

6. Part 63 is amended by adding subpart OOOOOO to read as follows:

Subpart OOOOOO—National Emission Standards for Hazardous Air Pollutants for Flexible Polyurethane Foam Production and Fabrication Area Sources

Sec.

Applicability and Compliance Dates

63.11414 Am I subject to this subpart?

63.11415 What are my compliance dates?

Standards and Compliance Requirements

63.11416 What are the standards for new and existing sources?

63.11417 What are the compliance requirements for new and existing sources?

Other Requirements and Information

63.11418 What General Provisions apply to this subpart?

63.11419 What definitions apply to this subpart?

63.11420 Who implements and enforces this subpart?

Tables to Subpart OOOOOO of Part 63

Table 1 to Subpart OOOOOO of Part 63—Applicability of General Provisions (40 CFR Part 63, Subpart A) to Subpart OOOOOO

Applicability and Compliance Dates

§ 63.11414 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate an area source of

hazardous air pollutant (HAP) emissions that meets the criteria in paragraph (a)(1) or (2) of this section.

(1) You own or operate a plant that produces flexible polyurethane foam or rebond foam as defined in § 63.1292 of subpart III.

(2) You own or operate a flexible polyurethane foam fabrication facility, as defined in § 63.11419.

(b) The provisions of this subpart apply to each new and existing affected source that meets the criteria listed in paragraphs (b)(1) through (4) of this section.

(1) A slabstock flexible polyurethane foam production affected source is the collection of all equipment and activities necessary to produce slabstock flexible polyurethane foam.

(2) A molded flexible polyurethane foam production affected source is the collection of all equipment and activities necessary to produce molded foam.

(3) A rebond foam production affected source is the collection of all equipment and activities necessary to produce rebond foam.

(4) A flexible polyurethane foam fabrication affected source is the collection of all equipment and activities at a flexible polyurethane foam fabrication facility where adhesives are used to bond foam to foam or other substrates. Equipment and activities at flexible polyurethane foam fabrication facilities which do not use adhesives to bond foam to foam or other substrates are not flexible polyurethane foam fabrication affected sources.

(c) An affected source is existing if you commenced construction or reconstruction of the affected source before April 4, 2007.

(d) An affected source is new if you commenced construction or reconstruction of the affected source on or after April 4, 2007.

(e) This subpart does not apply to research and development facilities, as defined in section 112(c)(7) of the Clean Air Act (CAA).

(f) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 63.11415 What are my compliance dates?

(a) If you own or operate an existing affected source, you must achieve compliance with the applicable provisions in this subpart by the date of publication of the final rule in the **Federal Register**.

(b) If you startup a new affected source on or before the date of publication of the final rule in the **Federal Register**, you must achieve compliance with the applicable provisions in this subpart not later than the date of publication of the final rule in the **Federal Register**.

(c) If you startup a new affected source after the date of publication of the final rule in the **Federal Register**, you must achieve compliance with the provisions in this subpart upon startup of your affected source.

Standards and Compliance Requirements

§ 63.11416 What are the standards for new and existing sources?

(a) If you own or operate a slabstock flexible polyurethane foam production affected source, you must meet the requirements in paragraph (b) of this section. If you own or operate a molded foam affected source, you must meet the requirements in paragraph (c) of this section. If you own or operate a rebond foam affected source, you must meet the requirements in paragraph (d) of this section. If you own or operate a flexible polyurethane foam fabrication affected source you must meet the requirements in paragraph (e) of this section.

(b) If you own or operate a new or existing slabstock polyurethane foam production affected source, you must comply with the requirements in either paragraph (b)(1) or (2) of this section.

(1) Comply with § 63.1293(a) or (b) of subpart III, except that you must use Equation 1 of this section to determine the HAP auxiliary blowing agent (ABA) formulation limit for each foam grade instead of Equation 3 of § 63.1297 of subpart III. You must use zero as the formulation limitation for any grade of foam where the result of the formulation equation (using Equation 1 of this section) is negative (i.e., less than zero):

$$ABA_{limit} = -0.2(IFD) - 19.1\left(\frac{1}{IFD}\right) - 15.3(DEN) - 6.8\left(\frac{1}{DEN}\right) + 36.5 \quad \text{(Equation 1)}$$

Where:

ABA_{limit} = HAP ABA formulation limitation, parts methylene chloride ABA allowed per hundred parts polyol (pph).
IFD = Indentation force deflection, pounds.
DEN = Density, pounds per cubic foot.

(2) Use no material containing methylene chloride for any purpose in any slabstock flexible foam production process.

(c) If you own or operate a new or existing molded foam affected source, you must comply with the requirements in paragraphs (c)(1) and (2) of this section.

(1) You must not use a material containing methylene chloride as an equipment cleaner to flush the mixhead or use a material containing methylene chloride elsewhere as an equipment cleaner in a molded flexible polyurethane foam process.

(2) You must not use a mold release agent containing methylene chloride in a molded flexible polyurethane foam process.

(d) If you own or operate a new or existing rebond foam affected source, you must comply with the requirements in paragraphs (d)(1) and (2) of this section.

(1) You must not use a material containing methylene chloride as an equipment cleaner in a rebond foam process.

(2) You must not use a mold release agent containing methylene chloride in a rebond foam process.

(e) If you own or operate a new or existing flexible polyurethane foam fabrication affected source, you must not use any adhesive containing methylene chloride in a flexible polyurethane foam fabrication process.

(f) You may demonstrate compliance with the requirements in paragraphs (b)(2) and (c) through (e) of this section using adhesive usage records, Material Safety Data Sheets, and engineering calculations.

§ 63.11417 What are the compliance requirements for new and existing sources?

(a) If you own or operate a slabstock flexible polyurethane foam production affected source, you must comply with the requirements in paragraph (b) of this section. If you own or operate a molded foam affected source, rebond foam affected source, or a loop slitter at a flexible polyurethane foam fabrication affected source you must comply with the requirements in paragraphs (c) and (d) of this section.

(b) Each owner or operator of a new or existing slabstock flexible

polyurethane foam production affected source who chooses to comply with § 63.11416(b)(1) must comply with paragraph (b)(1) of this section. Each owner or operator of a new or existing slabstock flexible polyurethane foam production affected source who chooses to comply with § 63.11416(b)(2) must comply with paragraphs (b)(2) and (3) of this section.

(1) You must comply with paragraphs (b)(1)(i) through (v) of this section.

(i) The monitoring requirements in § 63.1303 of subpart III.

(ii) The testing requirements in § 63.1304 or § 63.1305 of subpart III.

(iii) The reporting requirements in § 63.1306 of subpart III, with the exception of the reporting requirements in § 63.1306(d)(1), (2), (4), and (5) of subpart III.

(iv) The recordkeeping requirements in § 63.1307 of subpart III.

(v) The compliance demonstration requirements in § 63.1308(a), (c), and (d) of subpart III.

(2) You must submit a notification of compliance status report no later than 180 days after your compliance date. The report must contain the information detailed in § 63.9(h)(2)(i) paragraphs (A) and (G), and must contain this certification of compliance, signed by a responsible official, for the standards in § 63.11416(b)(2): ''This facility uses no material containing methylene chloride for any purpose on any slabstock flexible foam process and will not use it in the future.''

(3) You must maintain records of the information used to demonstrate compliance, as required in § 63.11416(f). You must maintain the records for 5 years, with the last 2 years of data retained on site. The remaining 3 years of data may be maintained off site.

(c) You must have a compliance certification on file by the compliance date. This certification must contain the statements in paragraph (c)(1), (2), or (3) of this section, as applicable, and must be signed by a responsible official.

(1) For a molded foam affected source:

(i) ''This facility does not use, and will not use in the future, any equipment cleaner to flush the mixhead which contains methylene chloride, or any other equipment cleaner containing methylene chloride in a molded flexible polyurethane foam process in accordance with § 63.11416(c)(1).''

(ii) ''This facility does not use, and will not use in the future, any mold release agent containing methylene chloride in a molded flexible polyurethane foam process in accordance with § 63.11416(c)(2).''

(2) For a rebond foam affected source:

(i) ''This facility does not use, and will not use in the future, any equipment cleaner which contains methylene chloride in a rebond flexible polyurethane foam process in accordance with § 63.11416(d)(1).''

(ii) ''This facility does not use, and will not use in the future, any mold release agent containing methylene chloride in a rebond flexible polyurethane foam process in accordance with § 63.11416(d)(2).''

(3) For a flexible polyurethane foam fabrication affected source containing a loop slitter: ''This facility does not use, and will not use in the future, any adhesive containing methylene chloride on a loop slitter process in accordance with § 63.11416(e).''

(d) For molded foam affected sources, rebond foam affected sources, and flexible polyurethane foam fabrication affected sources containing a loop slitter, you must maintain records of the information used to demonstrate compliance, as required in § 63.11416(f). You must maintain the records for 5 years, with the last 2 years of data retained on site. The remaining 3 years of data may be maintained off site.

Other Requirements and Information

§ 63.11418 What General Provisions apply to this subpart?

The provisions in 40 CFR part 63, subpart A, applicable to sources subject to § 63.11416(b)(1) are specified in Table 1 of this subpart.

§ 63.11419 What definitions apply to this subpart?

The terms used in this subpart are defined in the CAA; § 63.1292 of subpart III; § 63.8830 of subpart MMMMM; § 63.2 of subpart A; and in this section as follows:

Flexible polyurethane foam fabrication facility means a facility where pieces of flexible polyurethane foam are cut, bonded, and/or laminated together or to other substrates.

§ 63.11420 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as a State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency pursuant to 40 CFR subpart E, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency within your State.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the approval authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are No transferred to the State, local, or tribal agency.

(1) Approval of an alternative No-opacity emissions standard under § 63.6(g).

(2) Approval of a major change to test methods under § 63.7(e)(2)(ii) and (f). A ''major change to test method'' is defined in § 63.90.

(3) Approval of a major change to monitoring under § 63.8(f). A ''major change to monitoring'' is defined in § 63.90.

(4) Approval of a major change to recordkeeping/reporting under § 63.10(f). A ''major change to recordkeeping/reporting'' is defined in § 63.90.

Tables to Subpart OOOOOO of Part 63

As required in § 63.11418, you must comply with the requirements of the NESHAP General Provisions (40 CFR part 63, subpart A) as shown in the following table.

TABLE 1 TO SUBPART OOOOOO.—APPLICABILITY OF GENERAL PROVISIONS (40 CFR PART 63, SUBPART A) TO SUBPART OOOOOO

Subpart A reference	Applies to subpart OOOOOO?	Comment
§ 63.1	Yes.	
§ 63.2	Yes	Definitions are modified and supplemented by § 63.11419.
§ 63.3	Yes.	
§ 63.4	Yes.	
§ 63.5	Yes.	
§ 63.6(a)–(d)	Yes.	

TABLE 1 TO SUBPART OOOOOO.—APPLICABILITY OF GENERAL PROVISIONS (40 CFR PART 63, SUBPART A) TO SUBPART OOOOOO—Continued

Subpart A reference	Applies to subpart OOOOOO?	Comment
§ 63.6(e)(1)–(2)	Yes.	
§ 63.6(e)(3)	No	Owners and operators of subpart OOOOOO affected sources are No required to develop and implement a startup, shutdown, and malfunction plan.
§ 63.6 (f)–(g)	Yes.	
§ 63.6(h)	No	Subpart OOOOOO does No require opacity and visible emissions standards.
§ 63.6 (i)–(j)	Yes.	
§ 63.7	No	Performance tests No required by subpart OOOOOO.
§ 63.8	No	Continuous monitoring, as defined in subpart A, is No required by subpart OOOOOO.
§ 63.9(a)–(d)	Yes.	
§ 63.9(e)–(g)	No.	
§ 63.9(h)	No	Subpart OOOOOO specifies Noification of Compliance Status requirements.
§ 63.9 (i)–(j)	Yes.	
§ 63.10(a)–(b)	Yes	Except that the records specified in § 63.10(b)(2) are No required.
§ 63.10(c)	No.	
§ 63.10(d)(1)	Yes.	
§ 63.10(d)(2)–(3)	No.	
§ 63.10(d)(4)	Yes.	
§ 63.10(d)(5)	No.	
§ 63.10(e)	No.	
§ 63.10(f)	Yes.	
§ 63.11	No.	
§ 63.12	Yes.	
§ 63.13	Yes.	
§ 63.14	Yes.	
§ 63.15	Yes.	
§ 63.16	Yes.	

7. Part 63 is amended by adding subpart PPPPPP to read as follows:

Subpart PPPPPP—National Emission Standards for Hazardous Air Pollutants for Lead Acid Battery Manufacturing Area Sources

Sec.

Applicability and Compliance Dates

63.11421 Am I subject to this subpart?
63.11422 What are my compliance dates?

Standards and Compliance Requirements

63.11423 What are the standards and compliance requirements for new and existing sources?
63.11424 [Reserved]

Other Requirements and Information

63.11425 What General Provisions apply to this subpart?
63.11426 What definitions apply to this subpart?
63.11427 Who implements and enforces this subpart?

Applicability and Compliance Dates

§ 63.11421 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate a lead acid battery manufacturing plant that is an area source of hazardous air pollutants (HAP) emissions.

(b) This subpart applies to each new or existing affected source. The affected source is each lead acid battery manufacturing plant. The affected source includes all grid casting facilities, paste mixing facilities, three-process operation facilities, lead oxide manufacturing facilities, lead reclamation facilities, and any other lead-emitting operation that are associated with the lead acid battery manufacturing plant.

(1) An affected source is existing if you commenced construction or reconstruction of the affected source before April 4, 2007.

(2) An affected source is new if you commenced construction or reconstruction of the affected source on or after April 4, 2007.

(c) This subpart does not apply to research and development facilities, as defined in section 112(c)(7) of the Clean Air Act (CAA).

(d) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 63.11422 What are my compliance dates?

(a) If you own or operate an existing affected source, you must achieve compliance with the applicable provisions in this subpart by no later than 1 year after the date of publication of the final rule in the **Federal Register**.

(b) If you start up a new affected source on or before the date of publication of the final rule in the **Federal Register,** you must achieve compliance with the applicable provisions in this subpart not later than the date of publication of the final rule in the **Federal Register**.

(c) If you start up a new affected source after the date of publication of the final rule in the **Federal Register**, you must achieve compliance with the provisions in this subpart upon startup of your affected source.

Standards and Compliance Requirements

§ 63.11423 What are the standards and compliance requirements for new and existing sources?

(a) You must meet all the requirements in 40 CFR 60.372, 60.373, and 60.374, with the exception noted in paragraph (b) of this section.

(b) Existing sources are not required to conduct a performance test if a prior performance test was conducted using the same methods specified in 40 CFR 60.374 and either no process changes have been made since the test, or you can demonstrate that the results of the performance test, with or without

adjustments, reliably demonstrates compliance despite process changes.

(c) Sources without a prior performance test, as described in paragraph (b) of this section, must conduct a performance test using the methods specified in 40 CFR 60.374 by 180 days after the compliance date.

§ 63.11424 [Reserved]

Other Requirements and Information

§ 63.11425 What General Provisions apply to this subpart?

(a) The provisions in 40 CFR part 60, subpart A, applicable to this subpart are §§ 60.7 through 60.8, §§ 60.11 through 60.13, and § 60.17.

(b) The provisions in 40 CFR part 63, subpart A, applicable to this subpart are §§ 63.1 through 63.4, § 63.6(g), § 63.9(b) through (d), § 63.9(h), and §§ 63.12 through 63.16.

§ 63.11426 What definitions apply to this subpart?

The terms used in this subpart are defined in the CAA; 40 CFR 60.371; 40 CFR 60.2 for terms used in the applicable provisions of part 60, subpart A, as specified in § 63.11425(a); and § 63.2 for terms used in the applicable provisions of part 63, subpart A, as specified in § 63.11425(b).

§ 63.11427 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as a State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency pursuant to 40 CFR subpart E, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency within your State.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the approval authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(1) Approval of an alternative non-opacity emissions standard under § 63.6(g).

(2) Approval of a major change to test methods under 40 CFR 60.8(b). A ''major change to test method'' is defined in § 63.90.

(3) Approval of a major change to monitoring under 40 CFR 60.13(i). A ''major change to monitoring'' is defined in § 63.90.

(4) Approval of a major change to recordkeeping/reporting under 40 CFR 60.7(b) through (f). A ''major change to recordkeeping/reporting'' is defined in § 63.90.

8. Part 63 is amended by adding subpart QQQQQQ to read as follows:

Subpart QQQQQQ—National Emission Standards for Hazardous Air Pollutants for Wood Preserving Area Sources

Sec.

Applicability and Compliance Dates

63.11428 Am I subject to this subpart?
63.11429 What are my compliance dates?

Standards

63.11430 What are the standards?
63.11431 [Reserved]

Other Requirements and Information

63.11432 What General Provisions apply to this subpart?
63.11433 What definitions apply to this subpart?
63.11434 Who implements and enforces this subpart?

Applicability and Compliance Dates

§ 63.11428 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate a wood preserving operation that is an area source of hazardous air pollutant (HAP) emissions.

(b) The affected source is each new or existing wood preserving operation.

(1) An affected source is existing if you commenced construction or reconstruction of the affected source before April 4, 2007.

(2) An affected source is new if you commenced construction or reconstruction of the affected source on or after April 4, 2007.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 63.11429 What are my compliance dates?

(a) If you have an existing affected source, you must achieve compliance with applicable provisions in this subpart by the date of publication of the final rule in the **Federal Register**.

(b) If you startup a new affected source on or before the date of publication of the final rule in the **Federal Register**, you must achieve compliance with applicable provisions in this subpart not later than the date of publication of the final rule in the **Federal Register**.

(c) If you startup a new affected source after the date of publication of the final rule in the **Federal Register**, you must achieve compliance with applicable provisions in this subpart upon initial startup.

Standards

§ 63.11430 What are the standards?

(a) If you use a pressure treatment process with any wood preservatives containing chromium, arsenic, dioxins, or methylene chloride at a new or existing area source, the preservatives must be applied to the wood product inside a retort or similarly enclosed vessel.

(b) If you use a thermal treatment process with any wood preservatives containing chromium, arsenic, dioxins, or methylene chloride at a new or existing area source, the preservatives must be applied using process treatment tanks equipped with an air scavenging system to control emissions.

(c) You must prepare and operate according to a management practice plan to minimize air emissions from the preservative treatment of wood at a new or existing area source. You may use your standard operating procedures to meet the requirements for a management practice plan if it includes the minimum activities required for a management practice plan. The management practice plan must include, but is not limited to, the following activities:

(1) Minimize preservative usage;

(2) Maintain records on the type of treatment process and types and amounts of wood preservatives used at the facility;

(3) For the pressure treatment process, maintain charge records identifying pressure reading(s) inside the retorts (or similarly enclosed vessel);

(4) For the thermal treatment process, maintain records that the air scavenging system is in place and operated properly during the treatment process;

(5) Store treated wood product on drip pads or in a primary containment area to convey preservative drippage to a collection system until drippage has ceased;

(6) For the pressure treatment process, fully drain the retort prior to opening the retort door;

(7) Promptly collect any spills; and

(8) Perform relevant corrective actions or preventative measures in the event of a malfunction before resuming operations.

§ 63.11431 [Reserved]

Other Requirements and Information

§ 63.11432 What General Provisions apply to this subpart?

(a) If you own or operate a new or existing affected source, you must comply with the requirements of the General Provisions in 40 CFR part 63, subpart A, according to Table 1 to this subpart.

(b) You must submit an initial notification of applicability required by § 63.9(a)(2) no later than 90 days after the applicable compliance date specified in § 63.11429. The initial notification may be combined with the notification of compliance status required in paragraph (c) of this section. The notification of applicability must include the following information:

(1) The name and address of the owner or operator;

(2) The address (i.e., physical location) of the affected source; and

(3) An identification of the relevant standard, or other requirement, that is the basis of the notification and the source's compliance date.

(c) You must submit a notification of compliance status required by § 63.9(h) no later than 90 days after the applicable compliance date specified in § 63.11429. Your notification of compliance status must include this certification of compliance, signed by a responsible official, for the standards in § 63.11430: ''This facility complies with the management practices to minimize air emissions from the preservative treatment of wood in accordance with § 63.11430.''

(d) You must report any deviation from the requirements of this subpart within 30 days of the deviation.

§ 63.11433 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, § 63.2, and in this section as follows:

Air scavenging system means an air collection and control system that collects and removes vapors from a thermal treatment process vessel and vents the emissions to a vapor recovery tank that collects condensate from the vapors.

Chromated copper arsenate (CCA) means a chemical wood preservative consisting of mixtures of water-soluble chemicals containing metal oxides of chromium, copper, and arsenic. CCA is used in pressure treated wood to protect wood from rotting due to insects and microbial agents.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emissions limitation or management practice;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emissions limitation or management practice in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Pressure treatment process means a wood treatment process involving an enclosed vessel, usually a retort, and the application of pneumatic or hydrostatic pressure to expedite the movement of preservative liquid into the wood.

Responsible official means responsible official as defined in 40 CFR 70.2.

Retort means an airtight pressure vessel, typically a long horizontal cylinder, used for the pressure impregnation of wood products with a liquid wood preservative.

Thermal treatment process means a non-pressurized wood treatment process where the wood is exposed to a heated preservative.

Wood preserving means the pressure or thermal impregnation of chemicals into wood to provide effective long-term resistance to attack by fungi, bacteria, insects, and marine borers.

§ 63.11434 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as a State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency pursuant to 40 CFR subpart E, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(1) Approval of an alternative non-opacity emissions standard under § 63.6(g).

(2) Approval of a major change to test methods under § 63.7(e)(2)(ii) and (f). A ''major change to test method'' is defined in § 63.90

(3) Approval of a major change to monitoring under § 63.8(f). A ''major change to monitoring'' is defined in § 63.90.

(4) Approval of a major change to recordkeeping/reporting under § 63.10(f). A ''major change to recordkeeping/reporting'' is defined in § 63.90.

As required in § 63.11432, you must comply with the requirements of the NESHAP General Provisions (40 CFR part 63, subpart A) as shown in the following table.

TABLE 1 TO SUBPART QQQQQQ OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART QQQQQQ

Citation	Subject	Applies to subpart QQQQQQ?	Explanation
63.1(a)(1), (a)(2), (a)(3), (a)(4), (a)(6), (a)(10)–(a)(12) (b)(1), (b)(3), (c)(1), (c)(2), (c)(5), (e).	Applicability	Yes.	
63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3), (c)(4), (d).	Reserved	No.	
63.2	Definitions	Yes.	
63.3	Units and Abbreviations	Yes.	
63.4	Prohibited Activities and Circumvention.	Yes.	
63.5	Preconstruction Review and Notification Requirements.	No.	

TABLE 1 TO SUBPART QQQQQQ OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART QQQQQQ—Continued

Citation	Subject	Applies to subpart QQQQQQ?	Explanation
63.6(a), (b)(1)–(b)(5), (b)(7), (c)(1), (c)(2), (c)(5), (e)(1), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes.	
63.6(e)(3)(i), (e)(3)(iii)–(e)(3)(ix), (f), (g), (h)(1), (h)(2), (h)(4), (h)(5)(i)–(h)(5)(iii), (h)(v)(v), (h)(6)–(h)(9).	.....	No	Subpart QQQQQQ does not require startup, shutdown, and malfunction plan or contain emission or opacity limits.
63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv).	Reserved	No.	
63.7	Performance Testing Requirements.	No	Subpart QQQQQQ does not require performance tests.
63.8(a)(1), (a)(2), (a)(4), (b), (c), (d), (e), (f), (g).	Monitoring Requirements	No	Subpart QQQQQQ does not require monitoring of emissions.
63.8(a)(3)	Reserved	No.	
63.9(a), (b)(1), (b)(2), (b)(4), (b)(5), (c), (d), (h)(1), (h)(6), (i), (j).	Notification Requirements	Yes.	
63.9(b)(2)(i)–(b)(2)(v), (h)(2)(i)–(h)(2)(ii), (h)(3), (h)(5).	.....	Yes.	
63.9(e), (f), (g)	.....	No.	
63.9(b)(3), (h)(4)	Reserved	No.	
63.10(a), (b), (c)(1), (c)(5)–(c)(8), (c)(10)–(c)(14), (d), (e), (f).	Recordkeeping and Reporting Requirements.	No	Subpart QQQQQQ establishes requirements for a report of deviations within 30 days.
63.10(c)(2)–(c)(4), (c)(9)	Reserved	No.	
63.11	Control Device Requirements ..	No	Subpart QQQQQQ does not require flares.
63.12	State Authorities and Delegations.	Yes.	
63.13	Addresses	Yes.	
63.14	Incorporations by Reference	Yes.	
63.15	Availability of Information and Confidentiality.	Yes.	
63.16	Performance Track Provisions	Yes.	

[FR Doc. E7–5790 Filed 4–3–07; 8:45 am]

BILLING CODE 6560–50–P

Federal Register

Wednesday,
April 4, 2007

Part V

Department of Housing and Urban Development

24 CFR Part 92

HOME Investment Partnership Program; American Dream Downpayment Initiative and Amendments to Homeownership Affordability; Final Rule

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

24 CFR Part 92

[Docket No. FR–4832–F–02]

RIN 2501–AC93

HOME Investment Partnerships Program; American Dream Downpayment Initiative and Amendments to Homeownership Affordability

AGENCY: Office of the Secretary, HUD.

ACTION: Final rule.

SUMMARY: This rule follows publication of, and considers the public comments on, two earlier HUD rules. First, this rule makes final the March 30, 2004, interim rule establishing regulations for a downpayment assistance component under the HOME Investment Partnerships Program (HOME), referred to as the American Dream Downpayment Initiative (ADDI). Through the ADDI, HUD makes formula grants to participating jurisdictions under the HOME Program for the purpose of assisting low-income families to achieve homeownership. In addition, this rule also makes final HUD's November 22, 2004, interim rule, which revised and clarified the HOME Program homeownership affordability requirements of the HOME Investment Partnerships Program. In response to the public comments received on both interim rules, this final rule clarifies that the purchase of manufactured homes is an ADDI eligible activity, and broadens and clarifies the use of HOME funds to help preserve affordable housing previously assisted with HOME funds.

DATES: *Effective Date:* May 4, 2007.

FOR FURTHER INFORMATION CONTACT: Virginia Sardone, Director, Program Policy Division, Office of Affordable Housing Programs, Department of Housing and Urban Development, 451 Seventh Street, SW., Room 7164, Washington, DC 20410–7000; telephone (202) 708–2470. (This is not a toll-free number.) A telecommunications device for hearing- and speech-impaired persons (TTY) is available at (800) 877–8339 (Federal Information Relay Service).

SUPPLEMENTARY INFORMATION:

I. Background

A. The HOME Program

The HOME Investment Partnerships Program (HOME Program) is authorized under Title II of the Cranston-Gonzalez National Affordable Housing Act (42 U.S.C. 12704 *et seq.*) (NAHA). Through the HOME Program, HUD allocates funds by formula among eligible state and local governments to strengthen public-private partnerships and to expand the supply of decent, safe, sanitary, and affordable housing for very low-income and low-income families. Generally, HOME funds must be matched by nonfederal resources. State and local governments that become participating jurisdictions may use HOME funds to carry out multiyear housing strategies through acquisition, rehabilitation, and new construction of housing, and through tenant-based rental assistance. Participating jurisdictions may provide assistance in a number of eligible forms, including grants, loans, advances, equity investments, interest subsidies, and other forms of assistance that HUD approves. HUD's regulations for the HOME Program are located at 24 CFR part 92.

B. The March 30, 2004, Interim Rule Implementing the American Dream Downpayment Initiative

The American Dream Downpayment Act (Pub. L. 108–186, approved December 16, 2003) (ADDI statute) amended NAHA to establish a downpayment assistance component under the HOME program, referred to as the American Dream Downpayment Initiative (ADDI). Specifically, the ADDI statute established a separate formula under the HOME Program by which HUD allocates funds to states that are participating jurisdictions under the HOME Program and to participating jurisdictions within those states for the purpose of making downpayment assistance to low-income families who are first-time homebuyers for the purchase of single family housing that will serve as the family's principal residence. The ADDI statute revised section 271 of NAHA (12 U.S.C. 12881) to establish specific statutory requirements for administration of ADDI, including the allocation of funds.

With respect to allocation of funds, the ADDI statute established a formula that is based primarily on the need for assistance to homebuyers as measured by the percentage of low-income households residing in rental housing within the participating jurisdiction. This formula governs the allocation of ADDI funds. Among other requirements, the ADDI statute also established the definitions applicable to ADDI, authorized the use of ADDI funds for certain rehabilitation costs completed in conjunction with ADDI downpayment assistance, established new Consolidated Plan requirements, and prescribed other requirements regarding the allocation and use of ADDI funds. Through the statutory requirement that participating jurisdictions have a plan for conducting targeted outreach to public housing tenants and to families receiving rental assistance from public housing agencies, the ADDI statute envisioned that among the low-income families who will move from rental to homeownership are those families who are currently public housing residents or who are receiving rental assistance. ADDI provides a much-needed resource to participating jurisdictions to assist low-income families achieve the dream of homeownership.

On March 30, 2004 (69 FR 16758), HUD published an interim rule that established regulations at 24 CFR part 92 for ADDI. The interim rule codified the statutory formula (located at 42 U.S.C. 12821) for allocation of ADDI funds to HOME participating jurisdictions, identified eligible activities and costs under ADDI, and established other applicable requirements.

C. The November 22, 2004, Interim Rule Revising the HOME Program Homeownership Affordability Requirements

Section 215(b) of NAHA establishes affordability requirements for HOME-assisted homeownership housing. These requirements apply to both the initial sale to a HOME-assisted homebuyer and to any subsequent resale by that homebuyer during the applicable period of affordability. Specifically, the statute provides that participating jurisdictions must impose restrictions that either require that (1) the HOME-assisted housing be resold to another low-income homebuyer at an affordable price; or (2) the HOME-assisted housing may be resold to any homebuyer regardless of income, but the subsidy to the original homebuyer must be recaptured unless the net proceeds of the sale are insufficient.

On November 22, 2004 (69 FR 68050), HUD published an interim rule that amended the regulations at 24 CFR part 92 for homeownership housing under the HOME Program. The interim rule revised the affordability requirements for homeownership housing assisted under the HOME program. Specifically, the interim rule limited the amount of the HOME investment subject to recapture after the sale of a HOME-assisted homebuyer project during the period of affordability to the net proceeds of the sale. In addition, the rule created a provision to allow participating jurisdictions to preserve HOME-assisted homebuyer housing as

affordable housing by investing additional HOME funds to acquire the housing before foreclosure or at a foreclosure sale.

II. This Final Rule: Differences Between the March 30, 2004, ADDI Interim Rule, the November 22, 2004, Affordability Requirements Interim Rule, and This Final Rule

This final rule follows publication of the March 30, 2004, and the November 22, 2004, interim rules and takes into consideration the public comments received on the interim rules. After careful consideration of the public comments, HUD has made the following changes to the interim rules.

1. *Definition of first time homebuyer; clarifying language regarding manufactured housing as an eligible activity.* HUD is amending the definition of first time homebuyer in the HOME Investment Partnerships program definitions to include those individuals who own dwelling units not permanently affixed to a foundation (inadvertently omitted from the March 30, 2004, regulation); and amending the ADDI regulations to include statutory language on the purchase of manufactured housing as an ADDI eligible activity. Specifically, language has been included stating that individuals shall not be excluded from consideration as a first-time homebuyer on the basis that the individual owns or owned, as a principal residence during the three-year period prior to assistance with ADDI funds, a dwelling unit whose structure is not permanently affixed to a permanent foundation in accordance with local or other applicable regulations or not in compliance with state, local, or model building codes, or other applicable codes, and cannot be brought into compliance with such codes for less than the cost of constructing a permanent structure. Also, although the regulatory definition of ''housing'' includes manufactured housing and manufactured housing lots, the ADDI regulations now state that ADDI funds may be used to purchase manufactured housing units and manufactured housing lots; the manufactured housing must be connected to permanent utility hook-ups; and the land on which the manufactured housing is located must be owned by the manufactured housing owner, owned as cooperative, or subject to a leasehold interest with a term, at minimum, equal to the term of the mortgage financing on the unit or the period of affordability, whichever is greater.

2. *HOME funds for the preservation of affordable housing.* HUD has amended the HOME program's eligible administrative and planning costs to now include as eligible the preservation of affordable homeownership housing previously assisted with HOME funds. Also, the HOME program's prohibitions were amended to make clear that funds may be used for assistance to preserve affordability of homeownership housing. Additionally, § 92.254(a)(9) has been reorganized to more clearly explain that HOME funds may be used to acquire housing in default through a purchase option, right of first refusal, or other preemptive right before foreclosure or through acquisition at a foreclosure sale, as well as to assist another homebuyer in purchasing the housing. Furthermore, although HOME funds cannot be used to repay a loan made with HOME funds, HOME funds may be used to pay foreclosure costs. The regulations were also amended to clarify that the investment of additional HOME funds to preserve affordability is considered an amendment of the original project rather than a new project.

3. *HOME fund recaptures.* HUD has amended the final rule to clarify that HOME fund recaptures cannot exceed net proceeds, if there are in fact net proceeds. No substantive change is being made to the recapture requirement; but, rather, HUD is rewording the regulatory text for the sake of clarity.

III. Discussion of Public Comments on the March 30, 2004, Interim Rule Establishing ADDI Regulations

The public comment period on the ADDI interim rule closed on June 1, 2004, and HUD received 15 public comments. Comments were received from trade and professional organizations representing the realtor, homebuilder, and manufactured home industries; state and local community development agencies (as well as the national organizations representing these state and local agencies); private citizens; and non-profit downpayment assistance organizations. This section of the preamble presents a summary of the significant issues raised by the public comments and HUD's responses to those issues.

A. General Comments

Six commenters expressed general support for the ADDI interim rule. The commenters wrote that ''this program will help reduce home buying costs and allow people to achieve homeownership'' and that ADDI is ''focused on providing additional resources to HOME participating jurisdictions for homeownership activities.'' One commenter wrote that it was pleased that HUD included displaced homemakers and single parent households among those eligible to benefit from ADDI, and that the inclusion of condominiums and cooperative units within the definition of single family housing was a positive step.

The primary area of concern that commenters mentioned was the inability to use ADDI funds for ADDI administrative costs. Several commenters were concerned that even though the regulation permits HOME funds to be used for ADDI's administration and planning, lack of additional funds for ADDI administration will make oversight and execution of the ADDI program extremely difficult. Another area of concern related to the requirement that participating jurisdictions repay HOME/ADDI funds on homes that go into foreclosure.

Additional comments involved perceived negative connotations of manufactured housing, questions about eligible new construction costs, questions about the definition of first time homebuyer, and concerns that nonprofit homebuyer assistance organizations may not be permitted to participate in the ADDI. A breakdown of the comments by subject area follows.

B. Use of HOME Administrative Funds for ADDI Administrative Costs; ADDI Funding

The March 30, 2004, interim rule amended § 92.207 to make clear that a participating jurisdiction may expend HOME funds for payment of ADDI administrative expenses. The expended amount cannot exceed ten percent of the fiscal year HOME basic formula. ADDI funds cannot be used for administration costs of the ADDI program.

Comment: Not providing for additional funding for the ADDI program is unduly burdensome to participating jurisdictions. One commenter wrote that the intent of the ADDI program is to provide funding for a new homebuyer initiative rather than supplement funding for already existing programs. According to the commenter, new initiatives require new administrative costs; thus, additional funding is required in order to sufficiently get the ADDI program up and running. Another commenter wrote that a 10 percent allocation of HOME funds for both HOME and ADDI administrative costs is inadequate to meet program costs. An additional commenter wrote that HUD should add a participating jurisdiction's ADDI allocation to its HOME allocation to

calculate its ten percent program administration limit. One commenter asked HUD to amend the rule to allow all participating jurisdictions to expend up to 10 percent of their ADDI allocations on administrative costs.

HUD Response. ADDI is a downpayment assistance program under the HOME Program. Most participating jurisdictions already fund homebuyer projects with their HOME Program funds. Many of these projects are part of homebuyer programs that provide downpayment assistance to low-income homebuyers. Consequently, many participating jurisdictions will choose to implement ADDI as part of their existing homebuyer programs. HUD agrees that it may be burdensome to some participating jurisdictions to implement ADDI without additional funding for program administration. However, the ADDI statute does not provide additional funds for ADDI program administration from ADDI funds.

Comment: Congress intended to allow for the expenditure of ADDI funds as administrative expenses. One commenter wrote that Congress' silence on an administrative fee in the final statutory language for the ADDI program allows HUD the discretion to include a jurisdiction's FY 2004 and subsequent ADDI allocation into its HOME allocation for purposes of calculating an administrative fee. Another commenter wrote that Congress considered including administrative funds for ADDI and that the Senate Banking, Housing and Urban Affairs Committee amended the original Senate bill, S. 811, during its mark-up of the bill to include a five percent administrative provision for ADDI. A third commenter wrote that the ADDI statute should be interpreted to authorize the same level of administrative funding for ADDI activities as is already available for all other HOME activities, including those that provide homeownership assistance. Another commenter wrote that it interprets 24 CFR 92.602 of the HOME regulation as allowing a participating jurisdiction to use ADDI funds to finance ADDI project delivery costs.

HUD Response. HUD disagrees that Congress' silence on the eligibility of administrative costs in the final statutory language for the ADDI program allows HUD the discretion to include a jurisdiction's FY 2004 and subsequent ADDI allocations into its HOME allocations for purposes of calculating an administrative fee. As pointed out by a commenter, Congress considered including administrative funds for ADDI and the Senate Banking, Housing and Urban Affairs Committee amended the original Senate bill, S. 811, during its mark-up of the bill to permit five percent of ADDI funds to be used for administrative provision. However, this language was struck from the legislation before enactment. Section 92.602 identifies eligible costs under ADDI including staff and overhead costs directly related to carrying out an ADDI project, which are eligible project related soft costs under § 92.602(b)(3)(iv).

Comment: ADDI should be funded as a standalone program instead of a set-aside within the HOME program. One commenter made this suggestion.

HUD Response. Congress wrote the ADDI legislation to be a component of the HOME Program. The American Dream Downpayment Act amended the HOME statute (subtitle E of Title II of the Cranston-Gonzalez National Affordable Housing Act (42 U.S.C. 12821)) to create ADDI. The implementation of ADDI was facilitated because ADDI is a set-aside within the HOME Program.

C. Recaptured/Repaid Funds Due to Foreclosure

Several commenters on the ADDI rule expressed concern about HOME recapture and repayment requirements, which are applicable to ADDI under § 92.616. HUD addressed the concerns of these commenters by publishing the November 22, 2004, rule.

Comment: Validation is sought as to whether 24 CFR 92.254(a)(5) requires the participating jurisdiction to submit for HUD approval the resale and recapture provisions of the ADDI program before a participating jurisdiction may implement the program.

HUD Response. The HOME regulations at § 92.254(a)(5) require HOME participating jurisdictions to establish resale or recapture requirements that comply with the provisions of that section of the HOME rule and to set forth the requirements in their consolidated plans. In addition, § 91.220(g)(2)(ii) and § 91.320(g)(2)(ii) direct local participating jurisdictions and states, respectively, that will use HOME funds to assist homebuyers, to state the guidelines for resale or recapture as required in § 92.254. HUD reads § 92.254(a)(5) to include both HOME and ADDI funds used to assist homebuyers. Therefore, it is not necessary for a participating jurisdiction to separately submit for HUD approval the resale and recapture provisions it will use for the ADDI program unless the provisions used for ADDI projects differ from the provisions previously set forth in the consolidated plan for HOME homebuyer projects.

D. Manufactured Homes

Comment: Maintaining the current action plan language regarding manufactured homes is contrary to current federal and state policy. Two commenters wrote that the language requiring targeted outreach to residents and tenants of public and manufactured housing creates negative and inaccurate connotations for manufactured housing that are contrary to current policy. One of the commenters wrote that this language strongly implies that jurisdictions must have targeted plans to displace persons from manufactured homes.

HUD Response. The language added to the consolidated plan regulations at 24 CFR part 91 is the statutory requirement. Specifically, the language added to the action plan provisions for local HOME participating jurisdictions at § 91.220 and for states at § 91.320 requires a recipient of ADDI funds to include in its action plan a plan for conducting targeted outreach to residents and tenants of manufactured housing. Because the definition of single family housing in the ADDI statute and rule includes manufactured housing and a manufactured housing lot, the consolidated plan requirement regarding outreach to residents and tenants of manufactured housing has been read by commenters as contradicting the eligibility of manufactured housing as ADDI eligible single-family housing. However, tenants of the manufactured housing qualify as first-time homebuyers. In addition, ownership of manufactured housing that is not permanently affixed does not disqualify the family as a first-time homebuyer. In order to clarify the language in the interim rule regarding participating jurisdictions' responsibilities providing outreach to residents and tenants of manufactured housing, HUD is revising the definition of first-time homebuyer in the ADDI regulations that more closely tracks the statutory definition of single family housing. Specifically, the definition of first-time homebuyer now states that an individual shall not be excluded from consideration as a first-time homebuyer on the basis that the individual owns or owned, as a principal residence during the three-year period prior to assistance with ADDI funds, a dwelling unit whose structure is not permanently affixed to a permanent foundation in accordance with local or other applicable regulations or not in compliance with state, local, or model building codes, or other applicable codes, and cannot be brought into compliance with such

codes for less than the cost of constructing a permanent structure.

Comment: The definition of single family housing should be revised to use the exact statutory language pertaining to manufactured housing. Two commenters wrote that the statutory language provides that manufactured housing owned as a cooperative or subject to a leasehold interest is an eligible activity under ADDI. The commenters urged that this be clarified in the final rule.

HUD Response. HUD agrees that additional language is needed clarifying that the purchase of manufactured homes is an eligible activity. HUD has added language to § 92.602(a) stating that ADDI funds may be used to purchase a manufactured housing unit, manufactured housing lots, and that the manufactured housing unit must, at the time of project completion, be connected to permanent utility hook-ups and be located on land that is owned by the manufactured housing owner, owned as a cooperative, or is subject to a leasehold interest with a term equal to at least the term of the mortgage financing on the unit or the period of affordability (whichever is greater).

E. Nonprofit Downpayment Assistance Programs

Comment: The interim rule unfairly excludes certain nonprofit organizations from participation in ADDI. Two commenters objected to the limitation on subrecipients and contractors contained in the interim rule. The interim rule prohibits a participating jurisdiction from providing ADDI funds to an entity or organization that provides downpayment assistance, if the activities of that entity are financed by contributions, service fees, or other payments from the sellers of housing, whether or not made in conjunction with the sale of specific housing acquired with ADDI funds. The commenters wrote that this limitation goes beyond the statutory prohibition and unfairly excludes certain nonprofit organizations from participating in ADDI, because the commenters believe the statute can be interpreted to permit an entity to run two programs, one program with seller-provided funds and another—the ADDI program—without seller funds. In addition, the commenters objected to the rationale in the preamble to the interim rule, which provided that seller-financed downpayment assistance artificially inflated the fees charged to homebuyers in excess of the amount necessary to compensate sellers for their payment of certain closing charges or contributions to the cost of the downpayment.

HUD Response. The ADDI statute prohibits participating jurisdictions from using ADDI to provide funding to an entity or organization that provides downpayment assistance if the activities of that entity or organization are funded in whole or in part, directly or indirectly, by contributions, service fees, or other payments from the sellers of housing. The ADDI regulations at § 92.602(f) copy the statutory language and adds the following phrase: ''whether or not made in conjunction with the sale of specific housing acquired with ADDI funds.'' HUD purposefully added this language to better articulate the statutory prohibition against organizations that receive funds from sellers of housing. The prohibition applies to the entire organization, not just to specific programs of the organization.

The statement in the preamble about seller-funded downpayment programs is supported by a recent study. ''An Examination of Downpayment Gift Programs Administered by Non-profit Organizations'' (March 2005), prepared for HUD by Concentrance Consulting Group, found strong evidence that the cost of downpayment assistance added to the sales price, increased the loan amount, and eliminated any borrower equity in the property. This study can be found at: *http://www.hud.gov/offices/hsg/comp/rpts/dpassist/dpa2.pdf.*

F. Other Comments

Comment: The language relating to the usage of ADDI funds for new construction financing and the definition of ''single family home'' should be made more clear. One commenter requested that HUD clarify that, although ADDI funds cannot be used for hard or soft costs related to new construction, ADDI funds may be used for the acquisition and financing of new construction. Two commenters requested a clarification on the definition of single family housing and whether that definition includes both newly constructed and existing homes. One commenter suggested the rule should state that downpayment funds can only be used in association with the purchase or repair of existing homes. The commenter interpreted the interim rule to prohibit the use of ADDI funds for newly constructed homes.

HUD Response. The ADDI statute and § 92.602(a) of the ADDI regulations clearly state that the only eligible activities are downpayment assistance towards the purchase of single family housing by low-income families who are first-time homebuyers and rehabilitation that is completed in conjunction with the home purchase assisted with ADDI funds. Single family housing includes housing that is newly constructed. Section 92.601(b)(4) prohibits the use of ADDI funds for the development costs of new construction of housing or for rental assistance. Since ADDI funds can only be used for downpayment assistance towards the purchase of single family housing and for rehabilitation of the ADDI-assisted housing, ADDI funds can be used to assist low-income first-time homebuyers to purchase newly constructed housing, but not to develop or finance new construction.

Comment: The definition of first-time homebuyer should include a financial cap on ownership of other real estate. One commenter wrote that under the interim rule's definition of a first-time homebuyer, the first-time homebuyer could feasibly own other types of real estate prior to purchasing a first home, such as industrial, agricultural, commercial, and rental housing which did not include the buyer's residence. The commenter wrote that if HUD intends to allow for this kind of additional property ownership, the appraised value of such allowable property be capped at $300,000.

HUD Response. The purpose of the ADDI program is to assist low-income first-time homebuyers with downpayment assistance to purchase modest single family housing. An individual who has owned housing—whether or not it is the principal residence—within the three-year period before purchase of a home with ADDI assistance is not a first-time homebuyer, unless that person is a displaced homemaker or single parent as defined in the rule. If the participating jurisdiction is using the definition of ''annual income'' in § 5.609, the assets of the individual must be considered in determining whether the person is low-income.

Comment: The definition of low-income family at 24 CFR 92.2 should be waived for high-cost localities. One commenter wrote that HUD should allow a waiver of the definition of low-income families for higher cost areas where there may be a shortage of affordable housing for purchase by persons at 80 percent of area median income or below.

HUD Response. HUD disagrees with the commenter's suggestion that HUD waive the definition of low-income families in high cost areas. The definition of low-income families is statutorily based (42 U.S.C. 12704(10)) and cannot be waived. Moreover, allowing participating jurisdictions in

high cost areas in which there may be a shortage of affordable housing for low-income families to serve families with a higher income is contrary to the purpose of ADDI and will not resolve the affordable housing shortage for low-income families in that area.

Comment: Eligible ADDI costs should include pre-purchase housing inspections and housing counseling, regardless of ultimate ADDI assistance. One commenter wrote that pre-purchase housing inspections should be allowed as an eligible soft cost. The commenter wrote that in the event the purchase falls through due to the inspection uncovering problems that cancel the sale, HUD should allow participating jurisdictions to pay for those inspections with HOME administrative funds. The commenter also wrote that lead-based paint stabilization and clearance testing be included as an acceptable ADDI rehabilitation or soft cost, respectively. Another commenter wrote that HUD should recognize as an eligible ADDI cost the provision of pre-purchase services, such as housing counseling, to potential buyers who are ADDI-eligible, whether or not those eligible buyers are ultimately assisted with ADDI funds. Another commenter suggested that ADDI funds received by housing counseling organizations be chargeable as project costs even when the individual receiving the assistance is not immediately able to qualify for mortgage financing or receives such financing without ADDI assistance. The commenter also wrote that HUD should give ADDI funds directly to housing counseling agencies rather than filtering the funds through participating jurisdictions and urged that the 25 percent match associated with FY 2003 ADDI funds be waived in the case of awards to housing counseling organizations.

HUD Response. The ADDI statute and § 92.602(a) of the ADDI regulations identify eligible activities as downpayment assistance and home repairs. Section 92.602(b) identifies eligible project costs of ADDI projects. Included in eligible project costs are acquisition costs, rehabilitation costs, and related soft costs. Pre-purchase inspections and housing counseling are considered eligible soft costs, provided the eligible low-income, first-time homebuyer purchases single-family housing with ADDI assistance. If the purchase falls through and the sale is cancelled, there is no eligible ADDI project, and therefore, there are no eligible project soft costs. In this case, participating jurisdictions may use HOME administrative funds to pay for related soft costs expended on the cancelled ADDI project. Likewise, lead paint clearance testing is an eligible ADDI project related soft cost and lead paint stabilization is an eligible ADDI rehabilitation cost provided an eligible low-income, first-time homebuyer purchases the subject single-family housing with ADDI assistance.

HUD agrees that housing counseling is a crucial component of a successful homeownership program. However, the chief purpose of ADDI is to assist low-income families to achieve homeownership. HUD currently administers a housing counseling program through the Federal Housing Administration (FHA) that could assist persons who will not purchase single family housing with ADDI assistance. ADDI only authorizes HUD to ''award grants to participating jurisdictions to assist low-income families to achieve homeownership. * * *'' ''Participating jurisdiction'' is defined in the ADDI statute as a State or unit of general local government. Accordingly, housing counseling entities that are not participating jurisdictions are not eligible direct recipients of ADDI funds. The ADDI statute does not require participating jurisdictions to match ADDI funds. However, because FY 2003 ADDI funds are governed by the FY 2003 HOME appropriation act, not the ADDI statute, participating jurisdictions are required to match their FY 2003 ADDI funds. HUD cannot waive the statutory match requirement for these funds.

Comment: Clarification requested regarding 20 percent cap on rehabilitation. One commenter asked for clarification about the actual percentages the homebuyer may receive for rehabilitation. The commenter asked if, for example, a homebuyer is receiving $4,000 in downpayment assistance, whether the homebuyer is limited to rehabilitation expenditures of 20 percent of the $4,000 assistance total (in that case, $800), or can that homebuyer actually receive $6,000 in rehabilitation assistance (the maximum allowable under § 92.602(e)) as long as the participating jurisdiction's total entire ADDI rehabilitation amount does not exceed 20 percent of the fiscal year formula allocation.

HUD Response. According to ADDI statute, not more than 20 percent of the grant funds provided under the formula allocation to a participating jurisdiction may be used to provide assistance to low-income, first-time homebuyers for home repairs. The regulation at § 92.602(a)(2) states that ''total rehabilitation shall not exceed 20 percent of the participating jurisdiction's ADDI fiscal year formula allocation.'' Therefore, a homebuyer can receive ADDI funds for downpayment assistance and home repairs, subject to the maximum amount of assistance set forth at § 92.602(e)—the greater of 6 percent of the purchase price or $10,000—as long as the participating jurisdiction has not reached 20 percent of its ADDI formula allocation for home repairs. Thus, in the example the commenter set forth above, the homebuyer could receive up to $6,000 in rehabilitation assistance as long as the participating jurisdiction's entire ADDI rehabilitation amount does not exceed 20 percent of its fiscal year formula allocation.

Comment: ADDI funds should be disbursed in the same manner HOME funds are disbursed. One commenter, citing 24 CFR 92.502, wrote that certain costs associated with downpayment assistance will be charged against ADDI funds which involves per-household assistance caps. The commenter wrote that ADDI costs will be assigned to projects by HUD computers and those computers cannot effectively discern separate ADDI expenditures. The commenter wrote that rather than assigning ADDI funds to individual projects, HUD should disburse ADDI funds in the same manner as HOME funds, since local jurisdictions are better suited to decide how funds should be distributed.

HUD Response. ADDI funds are disbursed in the same manner as HOME funds through HUD's Integrated Disbursement and Information System (IDIS). However, ADDI funds cannot be separated from HOME funds in IDIS, and therefore, HUD has developed a report that uses a number of project identification factors to identify ADDI projects. These reports may be useful to participating jurisdictions to track ADDI disbursements. However, participating jurisdictions are free to maintain their own records of ADDI project disbursements. The sum of HOME and ADDI disbursements in IDIS will match a participating jurisdiction's records.

Comment: HUD should accept the median area purchase price developed by the real estate industry in the participating jurisdiction as the price for single family housing as per 24 CFR 92.254(a)(2)(iii). One commenter made this suggestion.

HUD Response. A participating jurisdiction that receives ADDI funds may use the Single Family Mortgage Limits under section 203(b) of the National Housing Act or it may determine 95 percent of the median area purchase price as set forth in 24 CFR 92.254(a)(2)(iii).

IV. Discussion of Public Comments on the November 22, 2004, Interim Rule on the HOME Program Homeownership Affordability Requirements

The public comment period on the November 22, 2004, interim rule closed on January 21, 2005, and HUD received seven public comments. Comments were received from state and local HOME participating jurisdictions, as well as the national organizations representing these state and local agencies, and private citizens. This section of the preamble presents a summary of the significant issues raised by the public comments and HUD's responses to those issues.

A. General Comments

Five commenters expressed general support for the interim rule. One commenter expressed ''strong support'' for the interim rule. Commenters wrote that they ''appreciate the clarification of the HOME affordability requirements relating to homebuyer projects'' and that ''the interim rule goes a long way towards addressing our concerns about participating jurisdictions' liability in cases of foreclosure.'' Another commenter wrote that it appreciated the renewed flexibility provided in the interim rule.

The November 22, 2004, interim rule made changes to the affordability requirements in § 92.254. One commenter wrote that it is supportive of the language in the interim rule that allows participating jurisdictions the flexibility to invest additional HOME funds in a HOME-assisted property in order to prevent foreclosure or acquire the HOME-assisted property at the foreclosure sale.

B. Net Proceeds Limitation

The November 22, 2004, interim rule limited recapture amounts in sales (voluntary and involuntary) of HOME-assisted homebuyer projects during the period of affordability to the net proceeds of the sale. One commenter wrote that HUD should ease the repayment requirement for HOME rental properties, homebuyer properties in which participating jurisdictions impose resale restrictions rather than recapture restrictions, and noncompliance other than foreclosure for housing that is subject to recapture.

HUD Response. HUD is not expanding the coverage of this rule to include the commenter's requests. However, HUD is aware of issues involving troubled HOME-assisted rental housing and is taking steps to address the issues, including using Technical Assistance funds to deploy experts to analyze specific projects and work out solutions.

Homeownership housing that is subject to resale restrictions must continue to be affordable for the period of affordability. This portion of the rulemaking only addresses housing that is subject to recapture, not housing subject to resale restrictions. The participating jurisdiction determines which option—recapture or resale—it will impose to ensure the housing meets the affordability requirements for the period. The participating jurisdiction's written agreement with the homebuyer sets forth its remedies for noncompliance. In addition, the rule permits additional investment of HOME funds to preserve previously assisted HOME homeownership housing, both housing subject to recapture and to resale restrictions. No substantive change is being made to the recapture requirement; but, rather, HUD is rewording the regulatory text for the sake of clarity.

C. Additional Home Funds for Preserving Affordability

The November 22, 2004, interim rule added language to the HOME regulations for the purpose of preserving the affordability of housing that was previously assisted with HOME funds and subject to the requirements of § 92.254(a). The new paragraph (a)(9) allows a participating jurisdiction to use additional HOME funds to acquire HOME-assisted homebuyer housing through a purchase option, right of first refusal, or other preemptive right before foreclosure, or to acquire the housing at the foreclosure sale, to undertake any necessary rehabilitation, and to provide assistance to another homebuyer. The section also allows participating jurisdictions to use HOME administrative funds under § 92.207 for this purpose.

Comment: The prohibition against using HOME funds to acquire a unit that has a HOME mortgage at a foreclosure sale may be problematic for some participating jurisdictions. One commenter questioned why participating jurisdictions are permitted to use additional HOME funds to preserve homebuyer housing for which HOME funds were already used but not when a jurisdiction forecloses on a defaulted HOME loan. Another commenter wrote that participating jurisdictions with limited resources would be unable to enforce affordability requirements of the HOME loan agreement because of the costs associated with foreclosing on the HOME loan and reselling the unit. Another commenter wrote that HUD needs to clarify the language in the interim rule if its intent was to permit the participating jurisdiction to use HOME administrative funds to acquire HOME-assisted homebuyer housing before foreclosure or at the foreclosure sale when the mortgage being foreclosed is a HOME loan.

HUD Response. In response to the comments, HUD is broadening the eligible uses of HOME funds to preserve affordable homeownership housing previously assisted with HOME funds in the final rule. Also, as noted earlier in the preamble, the HOME program's prohibitions have been amended to make clear that funds may be used for assistance to preserve affordability of homeownership housing. Additionally, § 92.254(a)(9) has been reorganized to more clearly explain that HOME funds may be used to acquire housing in default through a purchase option, right of first refusal, or other preemptive right before foreclosure or through acquisition at a foreclosure sale, as well as to assist another homebuyer in purchasing the housing. Furthermore, although HOME funds cannot be used to repay a loan made with HOME funds, HOME funds may be used to pay foreclosure costs. HOME funds cannot be used to repay a loan made with HOME funds because, as stated in the preamble to the interim rule, if a participating jurisdiction forecloses on a HOME loan, it receives the housing without additional cost to the HOME program. However, the rule now permits the use of HOME funds to pay the foreclosure costs (92.207(h)). The regulation also permits HOME funds to be used for any necessary rehabilitation and for assistance to another homebuyer and for the cost of owning/holding the housing pending resale to another homebuyer—regardless of whether the housing was acquired due to default of a HOME loan or loan superior to the HOME loan.

Comment: The use of HOME administrative funds to purchase a HOME-assisted property facing foreclosure may be problematic for some participating jurisdictions. A commenter expressed concern about the provision in the interim rule that allows participating jurisdictions to preserve the affordability of HOME-assisted homebuyer housing through the use of additional HOME funds to acquire the housing before foreclosure or at the foreclosure sale. According to the commenter, using HOME administrative funds to acquire the housing would be a burden to participating jurisdictions with limited administrative funds. In addition, the commenter wrote that the use of administrative funds to acquire the housing would not allow the participating jurisdiction to sell the

affected property to an eligible homebuyer wishing to assume the existing HOME loan without having to permanently lose the administrative funds expended to foreclose and possibly rehabilitate the home.

HUD Response. HUD is sympathetic to the commenter's concern and understands that it may not be feasible for a participating jurisdiction with limited HOME resources to use its administrative funds to preserve affordability. However, for participating jurisdictions with sufficient administrative funds available for this purpose, the regulatory language provides participating jurisdictions another option to preserve their affordable housing portfolio.

Comment: HUD should ensure that homebuyers purchasing homes already assisted with HOME funds that were acquired by the participating jurisdiction as a result of noncompliance can be assisted with HOME funds as direct homebuyer assistance. One commenter wrote that the interim rule should allow homebuyers purchasing housing previously assisted with HOME funds that was subsequently acquired by the participating jurisdiction before foreclosure or at the foreclosure sale to be assisted with HOME funds as direct homebuyer assistance, if they are eligible for HOME assistance.

HUD Response. The HOME regulation at § 92.214(a)(6) has long provided an exception to the HOME prohibited activities to permit HOME funds to be used to provide assistance to a homebuyer to acquire housing previously assisted with HOME funds during the period of affordability. Section § 92.254(a)(9) also permits HOME funds to be used to provide direct homebuyer assistance to an eligible homebuyer purchasing that property that the participating jurisdiction has acquired to preserve its affordability. HUD has amended the HOME prohibited activities to now allow HOME funds to be used for assistance to preserve affordability of homeownership housing in accordance with § 92.254(a)(9) to a project previously assisted with HOME funds during the proscribed period of affordability. This clarification will help to ensure the preservation of affordable housing and ensure that homebuyers purchasing homes already assisted with HOME funds that were acquired by the participating jurisdiction as a result of noncompliance can be assisted with HOME funds as direct homebuyer assistance.

IV. Findings and Certifications

Executive Order 12866, Regulatory Planning and Review

The Office of Management and Budget (OMB) reviewed this rule under Executive Order 12866 (entitled ''Regulatory Planning and Review''). OMB determined that this rule is a ''significant regulatory action'' as defined in section 3(f) of the order (although not an economically significant regulatory action, as provided under section 3(f)(1) of the order). The docket file is available for public inspection between the hours of 8 a.m. and 5 p.m. weekdays in the Regulations Division, Office of General Counsel, Department of Housing and Urban Development, 451 Seventh Street, SW., Room 10276, Washington, DC 20410–0500. Due to security measures at the HUD Headquarters building, please schedule an advance appointment to review the docket file by calling the Regulations Division at (202) 708–3055 (this is not a toll-free number).

Environmental Impact

A Finding of No Significant Impact with respect to the environment has been made for this final rule in accordance with HUD regulations at 24 CFR part 50, which implement section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332 *et seq.*). This Finding of No Significant Impact is available for public inspection between the hours of 8 a.m. and 5 p.m. weekdays in the Regulations Division, Office of General Counsel, Department of Housing and Urban Development, 451 Seventh Street, SW., Room 10276, Washington, DC 20410–0500. Due to security measures at the HUD Headquarters building, please schedule an appointment to review the finding by calling the Regulations Division at (202) 708–3055 (this is not a toll-free number).

Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. This rule makes final two interim rules that established regulations for the downpayment assistance program under the ADDI program and that revised and clarified the HOME program affordability requirements of the ADDI downpayment assistance program, respectively. This final rule is not imposing any additional regulatory requirements on participating jurisdictions. The majority of jurisdictions that are statutorily eligible to receive HOME formula allocations are relatively larger cities, counties, or states; thus, the final rule will not significantly affect a substantial number of small entities. Additionally, the final rule broadens the use of HOME funds to help preserve affordable homeownership housing. This expansion of the eligible use of funds actually benefits all participating jurisdictions, regardless of size. Accordingly, the undersigned certifies that this final rule will not have a significant economic impact on a substantial number of small entities.

Executive Order 13132, Federalism

Executive Order 13132 (entitled ''Federalism'') prohibits an agency from publishing any rule that has federalism implications if the rule either imposes substantial direct compliance costs on state and local governments and is not required by statute, or the rule preempts state law, unless the agency meets the consultation and funding requirements of section 6 of the order. This final rule will not have federalism implications and would not impose substantial direct compliance costs on state and local governments or preempt state law within the meaning of the order.

Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) (UMRA) establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments, and on the private sector. This final rule will not impose any federal mandates on any state, local, or tribal government, or on the private sector, within the meaning of UMRA.

Paperwork Reduction Act

Under section 3504(h) of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520), an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection displays a currently valid control number. There are no information collection requirements contained in this final rule.

Catalog of Federal Domestic Assistance

The Catalog of Federal Domestic Assistance Number for the HOME program is 14.239.

List of Subjects in 24 CFR Part 92

Administrative practice and procedure, Grant programs—housing and community development, Low and moderate income housing, Manufactured homes, Rent subsidies, Reporting and recordkeeping requirements.

■ Accordingly, for the reasons described in the preamble, HUD revises 24 CFR part 92 as follows:

PART 92—HOME INVESTMENT PARTNERSHIPS PROGRAM

■ 1. The authority citation for 24 CFR part 92 continues to read as follows:

Authority: 42 U.S.C. 3535d and 12701–12839.

■ 2. In § 92.2 revise the definition of ''First-time homebuyer'' to read as follows:

§ 92.2 Definitions.

* * * * *

First-time homebuyer means an individual and his or her spouse who have not owned a home during the three-year period prior to purchase of a home with assistance under the American Dream Downpayment Initiative (ADDI) described in subpart M of this part. The term first-time homebuyer also includes an individual who is a displaced homemaker or single parent, as those terms are defined in this section. An individual shall not be excluded from consideration as a first-time homebuyer on the basis that the individual owns or owned, as a principal residence during the three-year period, a dwelling unit whose structure is not permanently affixed to a permanent foundation in accordance with local or other applicable regulations or is not in compliance with State, local, or model building codes, or other applicable codes, and cannot be brought into compliance with the codes for less than the cost of constructing a permanent structure.

* * * * *

■ 3. Section 92.207 is amended to add a new paragraph (h) to read as follows:

§ 92.207 Eligible administrative and planning costs.

* * * * *

(h) *Preserving affordable housing already assisted with HOME funds.* Costs specified under § 92.254(a)(9) may be charged as an administrative cost or may be charged to the project as provided in § 92.254(a)(9). In addition, the foreclosure cost of a HOME-assisted rental housing project with a HOME loan in default is an eligible administrative cost.

■ 4. Revise § 92.214(a)(6) to read as follows:

§ 92.214 Prohibited activities.

* * * * *

(a) * * *

(6) Provide assistance (other than tenant-based rental assistance, assistance to a homebuyer to acquire housing previously assisted with HOME funds, or assistance to preserve affordability of homeownership housing in accordance with § 92.254(a)(9)) to a project previously assisted with HOME funds during the period of affordability established by the particular jurisdiction in the written agreement under § 92.504. However, additional HOME funds may be committed to a project for up to one year after project completion (see § 92.502), but the amount of HOME funds in the project may not exceed the maximum per-unit subsidy amount established under § 92.250.

* * * * *

■ 5. In § 92.254 revise paragraphs (a)(1), the second sentence of (a)(2)(ii), (a)(5)(ii)(A) introductory text, and (a)(9) to read as follows:

§ 92.254 Qualification as affordable housing: Homeownership.

(a) * * *

(1) The housing must be single family housing.

(2) * * *

(iii) * * * The participating jurisdiction must set forth the price for different types of single family housing for the jurisdiction. * * *

(5) * * *

(ii) * * *

(A) The following options for recapture requirements are acceptable to HUD. The participating jurisdiction may adopt, modify or develop its own recapture requirements for HUD approval. In establishing its recapture requirements, the participating jurisdiction is subject to the limitation that when the recapture requirement is triggered by a sale (voluntary or involuntary) of the housing unit, the amount recaptured cannot exceed the net proceeds, if any. The net proceeds are the sales price minus superior loan repayment (other than HOME funds) and any closing costs.

* * * * *

(9) *Preserving affordability of housing that was previously assisted with HOME funds.*

(i) To preserve the affordability of HOME-assisted housing a participating jurisdiction may use additional HOME funds for the following costs:

(A) The cost to acquire the housing through a purchase option, right of first refusal, or other preemptive right before foreclosure, or at the foreclosure sale. (The foreclosure costs to acquire housing with a HOME loan in default are eligible. However, HOME funds may not be used to repay a loan made with HOME funds.)

(B) The cost to undertake any necessary rehabilitation for the housing acquired.

(C) The cost of owning/holding the housing pending resale to another homebuyer.

(D) The cost to assist another homebuyer in purchasing the housing.

(ii) When a participating jurisdiction uses HOME funds to preserve the affordability of such housing, the additional investment must be treated as an amendment to the original project. The housing must be sold to a new eligible homebuyer in accordance with the requirements of § 92.254(a) within a reasonable period of time.

(iii) The total amount of the original and additional HOME assistance may not exceed the maximum per unit subsidy amount established under § 92.250. Alternatively to charging the cost to the HOME program under § 92.206, the participating jurisdiction may charge the cost to the HOME program under § 92.207 as a reasonable administrative cost of its HOME program, so that the additional HOME funds for the housing are not subject to the maximum per-unit subsidy amount. To the extent administrative funds are used, they may be reimbursed, in whole or in part, when the housing is sold to a new eligible homebuyer.

* * * * *

■ 6. Section 92.602 is amended to add a new paragraph (a)(3) to read as follows:

§ 92.602 Eligible activities.

(a) * * *

(3) *Manufactured housing.* ADDI funds may be used to purchase a manufactured housing unit and purchase a manufactured housing lot. The manufactured housing unit must, at the time of project completion, be connected to permanent utility hook-ups and be located on land that is owned by the manufactured housing owner, owned as a cooperative, or is subject to a leasehold interest with a term equal to at least the term of the mortgage financing on the unit or the period of affordability (whichever is greater).

* * * * *

Dated: March 23, 2007.

Roy A. Bernardi,

Deputy Secretary.

[FR Doc. E7–5960 Filed 4–3–07; 8:45 am]

BILLING CODE 4210–67–P

Federal Register

Wednesday,
April 4, 2007

Part VI

Department of Housing and Urban Development

24 CFR Part 234
Approval of Condominiums in Puerto Rico on Evidence of Presentment of Legal Documents; Final Rule

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

24 CFR Part 234

[Docket No. FR–5009–F–02]

RIN 2502–AI36

Approval of Condominiums in Puerto Rico on Evidence of Presentment of Legal Documents

AGENCY: Office of the Assistant Secretary for Housing-Federal Housing Commissioner, HUD.

ACTION: Final rule.

SUMMARY: This final rule amends the Department's regulations to provide that the date of recordation for purposes of obtaining Federal Housing Administration (FHA) approval of a condominium development in the Commonwealth of Puerto Rico for mortgage insurance under the section 234(c) program is the date the condominium legal documents are presented to the Commonwealth Office of the Property Registry. This final rule enables parties to obtain mortgage insurance upon presentment of legal documents, whether the condominium regime is under construction, proposed for construction, or was established by conversion. Instituting a single standard for approval of mortgage insurance will result in a reduction in risk, time, and cost for developers and help to increase FHA activity and homeownership opportunities in Puerto Rico. This final rule follows publication of a May 23, 2006, proposed rule on which HUD did not receive any public comments. Accordingly, HUD is adopting the May 23, 2006, proposed rule without change.

DATES: *Effective Date:* May 4, 2007.

FOR FURTHER INFORMATION CONTACT: Maynard T. Curry, Housing Program and Policy Specialist, Office of Single Family Program Development, Office of Housing, Department of Housing and Urban Development, 451 Seventh Street, SW., Room 9266, Washington, DC 20410–7000, telephone (202) 708–2121 (this is not a toll-free number). Individuals with speech or hearing impairments may access this number through TTY by calling the toll-free Federal Information Relay Service at (800) 877–8339.

SUPPLEMENTARY INFORMATION:

I. Background

On May 23, 2006, HUD published a proposed rule (71 FR 29754) for public comment to amend the Department's regulations governing Federal Housing Administration (FHA) approval of condominium developments in the Commonwealth of Puerto Rico for mortgage insurance under section 234 of the National Housing Act (12 U.S.C 1715y(c)) (the Act). Section 234(c) of the Act authorizes the Secretary of HUD to insure an individual mortgage on a one-family unit in a multifamily project and an undivided interest in the common areas and facilities that serve the project. Section 234(k) of the Act provides that, before FHA mortgage insurance can be placed on a unit in a condominium project converted from rental property, at least one year must elapse between the date of conversion and the date application for insurance is made. HUD's regulations implementing section 234 of the Act are codified at 24 CFR part 234.

In response to a severe backlog at the Puerto Rico Commonwealth Office of the Property Registry, which resulted in developers and proponents being responsible for paying assessments and costs associated with operating and maintaining the multifamily project as a condominium before mortgage insurance could be obtained, HUD issued a February 7, 2003, final rule that amended the definition of conversion. The final rule changed the definition of conversion with respect to Puerto Rico, to allow the running of the one-year waiting period to begin upon presentment for inscription (i.e., recording) of the required documentation.

This revision allowed the Department to approve condominium developments in Puerto Rico for FHA mortgage insurance on individual units within the multifamily project on the basis of evidence of presentment of legal documents and the parties' obtaining title insurance on each unit. The final rule thereby relieved Puerto Rican lenders from the heavy burden of holding section 234(c) loans without insurance, while waiting for documents to be recorded to meet the then-existing definition of conversion.

The May 23, 2006, proposed rule would revise the part 234 regulations to provide that, in the case of Puerto Rico, the date of presentment should serve as the date of recordation for all condominium regimes, which includes existing rental units that have been converted, units under construction, or units that are planned for construction. The proposed regulatory changes were designed to expand the scope of recordation while better reflecting the realities of the inscription process in Puerto Rico. Condominium plans would still have to comply with the legal requirements of the local jurisdiction. In addition, the proposed rule would not alter property rights, which are conferred by the legal documents themselves and not their recordation. The proposed rule would allow all condominium regimes in Puerto Rico to obtain FHA approval for mortgage insurance at the time of presentment of condominium documents. This would establish a uniform approach to the FHA mortgage insurance approval process by allowing FHA mortgage insurance to be placed on condominiums, whether they be conversions of existing rental units, units under construction, or units planned for construction, following presentment of the condominium's legal documents to the Commonwealth Office of the Property Registry.

For more detailed information regarding the proposed regulatory changes, please refer to the preamble of the May 23, 2006, proposed rule.

II. This Final Rule

This final rule follows the publication of a May 23, 2006, proposed rule. The public comment period on the proposed rule closed on July 24, 2006. HUD did not receive any public comments on the proposed rule. HUD, therefore, is issuing this final rule without change from the proposed rule.

III. Findings and Certifications

Information Collection Requirements

The information collection requirements contained in the section 234(c) program have been approved by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520) and assigned OMB Control Number 2502–0059. In accordance with the Paperwork Reduction Act, HUD may not conduct or sponsor, and a person is not required to respond to, a collection of information, unless the collection displays a currently valid OMB control number.

Environmental Review

This amendment is categorically excluded from environmental review under the National Environmental Policy Act (42 U.S.C. 4321). In keeping with the exclusion provided for in 24 CFR 50.19(c)(1), this amendment does not direct, provide for assistance, or loan and mortgage insurance for, or otherwise govern or regulate, real property acquisition, disposition, leasing, rehabilitation, alteration, demolition, or new construction, or establish, revise, or provide for standards for construction or construction materials, manufactured housing, or occupancy. Accordingly, this amendment is categorically excluded because it amends an existing

document where the existing document as a whole would not fall within the exclusion in 24 CFR 50.19(c)(1).

Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) (UMRA) establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. This final rule does not impose any federal mandates on any state, local, or tribal government or the private sector within the meaning of UMRA.

Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) generally requires an agency to conduct regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. This rule will not have a significant economic impact on a substantial number of small entities for the following reasons: (1) there are no anti-competitive discriminatory aspects of the rule with regard to small entities, and (2) there are no unusual procedures that would need to be complied with by small entities.

Executive Order 13132, Federalism

Executive Order 13132 (entitled ''Federalism'') prohibits, to the extent practicable and permitted by law, an agency from promulgating a regulation that has federalism implications and either imposes substantial direct compliance costs on state and local governments and is not required by statute, or preempts state law, unless the relevant requirements of section 6 of the executive order are met. This rule does not have federalism implications and does not impose substantial direct compliance costs on state and local governments or preempt state law within the meaning of the executive order.

Catalog of Federal Domestic Assistance

The Catalog of Federal Domestic Assistance numbers for 24 CFR part 234 are 14.117 and 14.133.

List of Subjects in 24 CFR Part 234

Condominiums, Mortgage insurance, Reporting and recordkeeping requirements.

■ Accordingly, for the reasons described in the preamble, HUD amends 24 CFR part 234 to read as follows:

PART 234—CONDOMINIUM OWNERSHIP MORTGAGE INSURANCE

■ 1. The authority citation for 24 CFR part 234 continues to read as follows:

Authority: 12 U.S.C. 1715b and 1715y; 42 U.S.C. 3535(d).

■ 2. Revise § 234.26(b) and (d)(1) to read as follows:

§ 234.26 Project requirements.

* * * * *

(b) *Plan of condominium ownership.* The project in which the unit is located shall have been committed to a plan of condominium ownership by a deed, or other recorded instrument, that is acceptable to the Commissioner. In the case of condominium documents in the Commonwealth of Puerto Rico, the Commissioner will accept documents presented for inscription (recordation) to the Commonwealth Office of the Property Registry so long as the mortgagor obtains a title insurance policy that reflects the condominium regime.

* * * * *

(d) * * *

(1) The deed of the family unit and the deed or other recorded instrument committing the project to a plan of condominium ownership must comply with legal requirements of the jurisdiction. In the case of condominium documents in the Commonwealth of Puerto Rico, the Department will accept documents presented for inscription (recordation) to the Commonwealth Office of Property Registry for certification purposes so long as the mortgagor obtains a title insurance policy that reflects the condominium regime.

* * * * *

Dated: March 20, 2007.

Brian D. Montgomery,

Assistant Secretary for Housing-Federal Housing Commissioner.

[FR Doc. E7–6088 Filed 4–3–07; 8:45 am]

BILLING CODE 4210–67–P

Federal Register

Wednesday,
April 4, 2007

Part VII

The President

Executive Order 13428—Renaming a National Forest in the Commonwealth of Puerto Rico

Federal Register
Vol. 72, No. 64
Wednesday, April 4, 2007

Presidential Documents

Title 3—

The President

Executive Order 13428 of April 2, 2007

Renaming a National Forest in the Commonwealth of Puerto Rico

By the authority vested in me as President by the Constitution and the laws of the United States of America, including section 1 of the Act of June 4, 1897 (16 U.S.C. 473) and section 1 of the Act of July 1, 1902 (48 U.S.C. 746), and to rename the Caribbean National Forest in the Commonwealth of Puerto Rico, it is hereby ordered as follows:

Section 1. The Caribbean National Forest in the Commonwealth of Puerto Rico is hereby renamed the ''El Yunque National Forest.''

Sec. 2. Previous references to the Caribbean National Forest in Executive Order 7059–A of June 4, 1935, and Executive Order 10992 of February 9, 1962, shall, for all purposes hereafter, be deemed references to the ''El Yunque National Forest.''

Sec. 3. This order shall be implemented in accordance with applicable law and subject to the availability of appropriations.

Sec. 4. This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, agencies, entities, officers, employees, or agents thereof, or any other person.

THE WHITE HOUSE,
April 2, 2007.

[FR Doc. 07–1704
Filed 4–3–07; 8:50 am]
Billing code 3195–01–P

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LIST OF PUBLIC LAWS

This is a continuing list of public bills from the current session of Congress which have become Federal laws. It may be used in conjunction with ''P L U S'' (Public Laws Update Service) on 202–741–6043. This list is also available online at *http://www.archives.gov/federal-register/laws.html*.

The text of laws is not published in the **Federal Register** but may be ordered in ''slip law'' (individual pamphlet) form from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402 (phone, 202–512–1808). The text will also be made available on the Internet from GPO Access at *http://www.gpoaccess.gov/plaws/index.html*. Some laws may not yet be available.

H.R. 1129/P.L. 110–16

To provide for the construction, operation, and maintenance of an arterial road in St. Louis County, Missouri. (Mar. 28, 2007; 121 Stat. 71)

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